Siemens PTI Report R068-20

MISO DPP 2018 April West Area Phase 2 Study

Prepared for

MISO

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Revision History

Date	Rev.	Description
09/28/2020	A	Draft Report
01/22/2021	B	Incorporate AECI Affected System Study Report
02/16/2021	C	Final Report

Contents

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Executive Summary

This report presents results of a System Impact Study (SIS) performed to evaluate the interconnection of the DPP 2018 April Phase 2 West Area Group (DPP West Area) generating facilities. The results for 2024 scenario are summarized below.

1.1 Project List

The DPP West Area study group has thirty-four (34) generation projects with a combined nameplate rating of 4447 MW. The DPP West Area generating facilities are listed in Table ES-1. The modeling details and projects' slider diagrams are shown in Appendix B.

Table ES-1: Generating Facilities in DPP 2018 April West Area Group

MISO Project #	Service Type	TO	County	State	Point of Interconnection	Fuel Type	ERIS Output	NRIS Output	SH MW	SPK MW
J952	ERIS	MDU	Corson	SD	McIntosh Junction-McLaughlin 115 kV	Wind	54	0	54.0	8.4
J953	External NRIS	ITCM	Johnson	IA	AMIL.IOW_AFRYT	Diesel	1.83	1.83	0.0	1.83
J954	External NRIS	ITCM	Johnson	IA	AMIL.IOW_AFRYT	Solar	1.4	1.4	0.7	1.4
J959	NRIS	SMMPA	Fayette	IA	Windsor 161 kV	Wind	150	150	150.0	23.4
J963	NRIS	ITCM	Cedar	IA	Bennett - Graham 69 kV	Diesel	9	9	0.0	9.0
J967	NRIS	Xcel	Mower	MN	Adams 345 kV	Wind	150	150	150.0	23.4
J975	ERIS	OTP	Cass	ND	Buffalo 115 kV	Wind	150	0	150.0	23.4
J981	NRIS	MEC	Washington	IA	Sub T 345 kV	Wind	200	200	200.0	31.2
J982	NRIS	MEC	Dickinson, Emmet	IA	Obrien County - Kossuth 345 kV	Wind	300	300	300.0	46.8
J1001	NRIS	Xcel	Lincoln	MN	Buffalo Ridge 115 kV	Solar	40	40	20.0	40.0
J1024	NRIS	MEC	Nodaway	MO	J611 - Clarinda 161 kV	Wind	200	200	200.0	31.2
J1040	NRIS	MDU	McIntosh	ND	Wishek Junction 230 kV	Wind	250	250	250.0	39.0
J1045	NRIS	Xcel	Murray	MN	Fenton - Chanarambie 115 kV	Battery	20	20	20.0	20.0

MISO Project #	Service Type	TO	County	State	Point of Interconnection	Fuel Type	ERIS Output	NRIS Output	SH MW	SPK MW
J1050	NRIS	ITCM	Boone, Hamilton	IA	Doud Tap 161 kV	Wind	225	225	225.0	35.1
J1072	NRIS	Xcel	Mower	MN	Adams 345 kV	Solar	150	150	75.0	150.0
J1084	NRIS	ITCM	Clinton	IA	Rock Creek 345 kV	Solar	150	150	75.0	150.0
J1092	NRIS	Xcel	Saint Croix	WI	Three Lakes 115 kV	Solar	100	100	50.0	100.0
J1098	NRIS	Xcel	Jackson	MN	Lakefield 345 kV	Solar	40	40	20.0	40.0
J1105	NRIS	Xcel	Dakota	MN	Hampton Corners 345 kV	Solar	200	200	100.0	200.0
J1106	NRIS	Xcel	Redwood	MN	Lyon County - Cedar Mountain 345 kV	Wind	414	414	414.0	64.6
J1110	NRIS	SMMPA	Mower	MN	North Austin 161 kV	Solar	100	100	50.0	100.0
J1122	NRIS	MEC	Pottawattamie	IA	Council Bluffs - Fallow Avenue 345 kV	Wind	200	200	200.0	31.2
J1124	NRIS	SMMPA	Olmsted	MN	Byron 345 kV	Solar	100	100	50.0	100.0
J1128	NRIS	SMMPA	Freeborn	MN	Hayward - Murphy Creek 161 kV	Solar	150	150	75.0	150.0
J1131	NRIS	MEC	Scott	IA	Sub 56 161 kV	Solar	100	100	50.0	100.0
J1132	NRIS	ITCM	Union	IA	Creston East 69 kV	Solar	50	50	25.0	50.0
J1135	NRIS	ITCM	Des Moines	IA	Huntwoods 69 kV	Solar	50	50	25.0	50.0
J1140	NRIS	MP	Benton	MN	Langola Tap 115 kV	Solar	80	80	40.0	80.0
J1164	NRIS	ITCM	Rock	MN	Magnolia 161 kV	Solar	80	80	40.0	80.0
J1169	NRIS	Xcel	McCook	SD	Grant 115 kV	Solar	50	50	25.0	50.0
J1174	NRIS	ITCM	Worth	IA	Bison - Colby 345 kV	Solar	165	165	82.5	165.0
J1175	NRIS	ITCM	Worth	IA	Bison - Colby 345 kV	Wind	165	165	82.5	165.0
J1181	NRIS	ITCM	Chickasaw	IA	Hazleton - Mitchell county 345 kV	Wind	200	200	200.0	31.2
J1187	NRIS	GRE	Mercer	ND	Stanton 230 kV	Wind	151.8	151.8	151.8	23.7

1.2 Reactive Power Requirements for Non-Synchronous Generation (FERC Order 827)

For non-synchronous generation projects in the DPP 2018 April West Area study group, if they do not have signed Generator Interconnection Agreement (GIA) or Provisional GIA (PGIA) by September 21, 2016, they are required to provide dynamic reactive power within the range of 0.95 leading to 0.95 lagging at the high-side of the generator substation.

All non-synchronous generation projects in this study group are required to meet the reactive power requirements per FERC Order 827.

The reactive power requirement analysis results are summarized as following:

- J959, J981, J982, J1024, J1072, J1084, J1105, J1106, J1110, J1124, J1128, J1164, and J1187 do not meet the reactive power requirements per FERC Order 827.
- All other non-synchronous generation projects can meet the reactive power requirements per FERC Order 827.

1.3 Total Network Upgrades for all Projects

The cost allocation of Network Upgrades for the study group reflects responsibilities for mitigating system impacts based on Interconnection Customer-elected level of Network Resource Interconnection Service as of the System Impact Study report date. The total cost of network upgrades in the interconnection plan required for each generation project is listed in Table ES-2. The costs for Network Upgrades are planning level estimates and subject to be revised in the facility studies.

Table ES-2: Total Cost of Network Upgrades for DPP 2018 April West Area Generation Projects

Project Num	ERIS Network Upgrades ($)													NRIS Network Upgrades ($)	Inter-connection Substation TO NUs ($)	TO's Inter-connection Facilities (TOIF)	SNU ($)	Total Network Upgrade Cost (Exclude TOIF & Affected System) ($)	M2 Received ($)	M3 Received ($)	M4 ($)
	Base Case NUs	MWEX Voltage Stability	MISO Thermal & Voltage	Transient Stability	Short Circuit	GRE LPC	MDU LPC	OTP LPC	CIPCO AFS	MPC AFS	PJM AFS	AECI AFS	SPP AFS								
J952	$0	$0	$196,182	$0	$0	$0	$0	$0	$0	$0	$0	$0	$8,700,000	$0	$4,476,041	$377,208	$0	$4,672,223	$216,000	$400,435	$318,010
J953	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$8,000	$0	$0
J954	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,600	$0	$0
J959	$403,887	$0	$325,858	$0	$0	$0	$0	$0	$37,301	$0	$0	$0	$50,359	$0	$4,718,628	$845,175	$0	$5,448,374	$600,000	$0	$489,675
J963	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$23,200	$0	$0
J967	$1,211,662	$0	$3,734,443	$0	$0	$0	$0	$0	$0	$0	$0	$0	$74,983	$0	$928,500	$1,705,500	$0	$5,874,605	$600,000	$111,927	$462,994
J975	$0	$0	$4,350,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$215,892	$0	$479,091	$1,043,191	$0	$4,829,091	$600,000	$1,558,786	$0
J981	$0	$0	$3,300	$0	$0	$0	$0	$0	$0	$0	$7,650,000	$0	$0	$0	$7,500,000	$2,500,000	$0	$7,503,300	$800,000	$0	$700,660
J982	$16,155,499	$0	$47,855	$0	$0	$0	$0	$0	$0	$0	$6,410,000	$0	$268,197	$0	$14,000,000	$1,250,000	$0	$30,203,354	$1,200,000	$2,354,531	$2,486,140
J1001	$0	$0	$9,901	$0	$0	$0	$0	$0	$0	$0	$0	$0	$34,839	$0	$8,265,000	$1,419,000	$0	$8,274,901	$160,000	$345,292	$1,149,688
J1024	$0	$0	$1,533,003	$0	$0	$0	$0	$0	$0	$0	$0	$0	$12,000,000	$7,388,443	$9,100,000	$1,000,000	$0	$18,021,447	$800,000	$1,510,089	$1,294,200
J1040	$0	$0	$114,733,019	$0	$0	$0	$48,400,000	$0	$0	$2,323,563	$0	$0	$642,042	$0	$397,037	$397,037	$0	$163,530,056	$1,000,000	$6,723,874	$24,982,137
J1045	$0	$0	$9,901	$0	$0	$0	$0	$0	$0	$0	$0	$0	$18,588	$0	$0	$0	$0	$9,901	$80,000	$120,333	$0
J1050	$0	$0	$31,353	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,000,000	$18,345	$408,508	$403,313	$0	$458,206	$900,000	$0	$0
J1072	$1,615,550	$0	$219,957	$0	$0	$0	$0	$0	$0	$0	$0	$0	$74,983	$0	$928,500	$1,705,500	$0	$2,764,006	$600,000	$80,963	$0
J1084	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$9,770,000	$0	$0	$0	$1,294,462	$661,704	$0	$1,294,462	$600,000	$0	$0
J1092	$10,904,962	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$57,759	$0	$1,511,000	$1,125,000	$0	$12,415,962	$400,000	$0	$2,083,192
J1098	$0	$0	$96,800,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$252,503	$10,000,000	$0	$0	$0	$106,800,000	$160,000	$225,567	$20,974,433
J1105	$4,442,762	$0	$11,400,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$126,630	$0	$2,267,000	$1,991,000	$0	$18,109,762	$800,000	$738,148	$2,083,805
J1106	$144,591,717	$0	$208,251	$0	$0	$0	$0	$0	$0	$0	$0	$0	$323,611	$0	$12,975,000	$2,434,000	$0	$157,774,968	$1,656,000	$4,314,168	$25,584,826
J1110	$403,887	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,419,388	$0	$4,761,550	$341,450	$0	$5,165,437	$400,000	$0	$633,087
J1122	$0	$0	$36,304	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$144,859	$14,000,000	$1,250,000	$0	$14,181,162	$800,000	$1,350,268	$685,964
J1124	$2,423,325	$0	$33,353	$0	$0	$0	$0	$0	$0	$0	$0	$0	$54,356	$0	$1,594,400	$1,097,700	$0	$4,051,078	$400,000	$0	$410,216
J1128	$0	$0	$13,900,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,882,204	$0	$5,050,622	$740,020	$0	$18,950,622	$600,000	$1,338,204	$1,851,920
J1131	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$825,000	$1,200,000	$0	$825,000	$400,000	$0	$0
J1132	$0	$0	$3,300	$0	$0	$0	$0	$0	$1,988,000	$0	$0	$0	$0	$3,748,353	$227,244	$487,844	$0	$3,978,897	$200,000	$330,511	$265,268
J1135	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$558,384	$0	$0	$200,000	$0	$0
J1140	$27,464,348	$0	$11,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$52,363	$0	$7,981,822	$374,024	$0	$46,446,170	$400,000	$969,933	$7,919,301

Project Num	ERIS Network Upgrades ($)													NRIS Network Upgrades ($)	Inter-connection Substation TO NUs ($)	TO's Inter-connection Facilities (TOIF)	SNU ($)	Total Network Upgrade Cost (Exclude TOIF & Affected System) ($)	M2 Received ($)	M3 Received ($)	M4 ($)
	Base Case NUs	MWEX Voltage Stability	MISO Thermal & Voltage	Transient Stability	Short Circuit	GRE LPC	MDU LPC	OTP LPC	CIPCO AFS	MPC AFS	PJM AFS	AECI AFS	SPP AFS								
J1164	$0	$0	$14,851	$0	$0	$0	$0	$0	$0	$0	$0	$0	$759,941	$0	$6,908,747	$396,282	$0	$6,923,598	$800,000	$3,874,879	$0
J1169	$0	$0	$11,551	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,968,089	$0	$5,485,000	$1,054,000	$0	$5,496,551	$200,000	$293,034	$606,276
J1174	$0	$0	$6,671,617	$0	$0	$0	$0	$0	$9,959	$0	$0	$0	$8,526,060	$0	$5,797,466	$461,139	$0	$12,469,083	$1,200,000	$996,501	$297,316
J1175	$0	$0	$13,346,535	$0	$0	$0	$0	$0	$19,918	$0	$0	$0	$8,526,060	$0	$5,797,466	$461,139	$0	$19,144,001	$1,200,000	$1,390,809	$1,237,992
J1181	$1,211,662	$0	$3,866,389	$0	$0	$0	$0	$0	$32,823	$0	$5,920,000	$0	$80,191	$0	$12,653,333	$892,278	$0	$17,731,385	$800,000	$629,023	$2,117,254
J1187	$0	$0	$843,076	$0	$0	$2,500,000	$0	$0	$0	$5,776,437	$0	$0	$421,102	$38,100,000	$1,177,041	$514,699	$0	$42,620,117	$607,200	$1,627,631	$6,289,193
Total ($)	**$210,829,263**	**$0**	**$283,330,000**	**$0**	**$0**	**$2,500,000**	**$48,400,000**	**$0**	**$2,088,000**	**$8,100,000**	**$29,750,000**	**$0**	**$57,530,140**	**$59,400,000**	**$141,508,458**	**$28,171,888**	**$0**	**$745,967,721**	**$19,416,000**	**$31,284,905**	**$104,923,547**

The study was performed under the direction of MISO by Siemens PTI and an ad hoc study group. The ad hoc study group was formed to review the study scope, methodology, models, and results. The ad hoc study group consisted of representatives from the interconnection customers and the following utility companies – Ameren, American Transmission Company, Basin Electric Power, Cedar Falls Utilities, Central Iowa Power Cooperative, City of Springfield (IL) Water Light & Power, Columbia (MO) Water and Light, Commonwealth Edison, Corn Belt Power Cooperative, Dairyland Power, Great River Energy, ITC Midwest, Lincoln Electric System, Manitoba Hydro, MidAmerican Energy Company, MISO, Minnesota Power, Minnkota Power, Missouri River Energy Services, Montana-Dakota Utilities Co., Muscatine Power & Water, Nebraska Public Power District, Northwestern Public Service, Omaha Public Power District, Otter Tail Power, PJM, Southern Illinois Power Cooperative, Southern Minnesota Municipal Power Agency, SPP, Western Area Power Administration, and Xcel Energy.

1.4 Per Project Summary

This section provides estimated cost of Network Upgrades on a per project basis for the 2024 scenario. The shared cost of Network Upgrades for all the generation projects are listed below.

The Interconnection Customers are required to mitigate the constraints observed from the 2024 scenario.

1.4.1 J952 Summary

Network Upgrade	Cost	J952	NUs Type	Self Funding?
Merricourt-Wishek 230 kV	$15,000,000	$161,529	MISO SH	Yes
1×40 Mvar switched capacitor at Oakes 230 kV (620362)	$2,000,000	$34,653	MISO Voltage	Yes
SPP ERIS Network Upgrades	$21,700,000	$8,700,000	SPP	Pending
Total Cost Per Project for Actual ERIS Elections for each Project		**$8,896,182**		

1.4.2 J953 Summary

Network Upgrade	Cost	J953	NUs Type	Self Funding?
No Network Upgrades		$0		
Total Cost Per Project for Actual NRIS Elections for each Project		**$0**		

1.4.3 J954 Summary

Network Upgrade	Cost	J954	NUs Type	Self Funding?
No Network Upgrades		$0		
Total Cost Per Project for Actual NRIS Elections for each Project		**$0**		

1.4.4 J959 Summary

Network Upgrade	Cost	J959	NUs Type	Self Funding?
Hazel Creek-Scott Co. 345 kV	$210,829,263	$403,887	Base Case NU Hazel Creek-Scott Co. 345 kV	Yes
Hazleton-Arnold 345 kV	$1,280,000	$325,858	MISO SH	ITCM: Yes MEC: Yes
Liberty-Hickory Crk 161 kV	$100,000	$37,301	CIPCO	CIPCO: No
SPP NRIS Network Upgrades	$35,830,140	$50,359	SPP	Pending
Total Cost Per Project for Actual NRIS Elections for each Project		**$817,405**		

1.4.5 J963 Summary

Network Upgrade	Cost	J963	NUs Type	Self Funding?
No Network Upgrades		$0		
Total Cost Per Project for Actual NRIS Elections for each Project		**$0**		

1.4.6 J967 Summary

Network Upgrade	Cost	J967	NUs Type	Self Funding?
Hazel Creek-Scott Co. 345 kV	$210,829,263	$1,211,662	Base Case NU Hazel Creek-Scott Co. 345 kV	Yes
J1181 POI-Hazleton 345 kV	$600,000	$155,837	MISO SH	MEC: Yes ITCM: Yes
Hazleton-Arnold 345 kV	$1,280,000	$284,077	MISO SH	ITCM: Yes MEC: Yes
Wabaco-Rochester 161 kV	$11,000,000	$0 [1]	MISO SH	Pending
Wabaco-Alma 161 kV	$6,300,000	$3,294,529	MISO SH	Pending
SPP NRIS Network Upgrades	$35,830,140	$74,983	SPP	Pending
Total Cost Per Project for Actual NRIS Elections for each Project		**$5,021,088**		

Note 1: J967 will assume $3,845,005 cost responsibility if the Wabaco-Rochester 161 kV rebuild is no longer an approved MTEP Appendix A project.

1.4.7 J975 Summary

Network Upgrade	Cost	J975	NUs Type	Self Funding?
Hubbard-Badoura 230 kV	$1,350,000	$1,350,000	MISO SH	Yes
Buffalo 345-230-41.6 kV xfmr #2	$3,000,000	$3,000,000	MISO SH	Yes
SPP ERIS Network Upgrades	$21,700,000	$215,892	SPP	Pending
Total Cost Per Project for Actual ERIS Elections for each Project		**$4,565,892**		

1.4.8 J981 Summary

Network Upgrade	Cost	J981	NUs Type	Self Funding?
1×40 Mvar switched capacitor at Oakes 230 kV (620362)	$2,000,000	$3,300	MISO Voltage	Yes
Nelson;B- Electric JCT;R 345 kV	$36,200,000	$7,650,000	PJM	No
Total Cost Per Project for Actual NRIS Elections for each Project		**$7,653,300**		

1.4.9 J982 Summary

Network Upgrade	Cost	J982	NUs Type	Self Funding?
Hazel Creek-Scott Co. 345 kV	$210,829,263	$16,155,499	Base Case NU Hazel Creek-Scott Co. 345 kV	Yes
1×40 Mvar switched capacitor at Oakes 230 kV (620362)	$2,000,000	$47,855	MISO Voltage	Yes
Nelson;B- Electric JCT;R 345 kV	$36,200,000	$6,410,000	PJM	No
SPP NRIS Network Upgrades	$35,830,140	$268,197	SPP	Pending
Total Cost Per Project for Actual NRIS Elections for each Project		**$22,881,551**		

1.4.10 J1001 Summary

Network Upgrade	Cost	J1001	NUs Type	Self Funding?
1×40 Mvar switched capacitor at Oakes 230 kV (620362)	$2,000,000	$9,901	MISO Voltage	Yes
SPP NRIS Network Upgrades	$35,830,140	$34,839	SPP	Pending
Total Cost Per Project for Actual NRIS Elections for each Project		**$44,740**		

1.4.11 J1024 Summary

Network Upgrade	Cost	J1024	NUs Type	Self Funding?
J1024 POI-Clarinda 161 kV	$700,000	$700,000	MISO SH	Yes
Adams-Creston 161 kV	$800,000	$800,000	MISO SH	MEC: Yes
1×40 Mvar switched capacitor at Oakes 230 kV (620362)	$2,000,000	$33,003	MISO Voltage	Yes
Reconductor MCKSBRG-Winterset	$10,000,000	$6,367,594	NRIS	ITCM: Yes MEC: Yes
Council Bluffs-S3456 345 kV Terminal Equipment Upgrade	$200,000	$31,263	NRIS	MEC: Yes OPPD: No
Winterset-Norwalk Structure Replacements	$300,000	$189,586	NRIS	ITCM: Yes MEC: Yes
Adams-Creston Structure Replacements	$800,000	$800,000	NRIS	MEC: Yes WAPA: No
SPP ERIS Network Upgrades	$21,700,000	$12,000,000	SPP	Pending
Total Cost Per Project for Actual NRIS Elections for each Project		**$20,921,447**		

1.4.12 J1040 Summary

Network Upgrade	Cost	J1040	NUs Type	Self Funding?
Heskett-J302 POI 230 kV	$81,500,000	$81,500,000	MISO SH	Yes
Fox Tail-Tatanka North 230 kV	$1,500,000	$1,500,000	MISO SH	Yes
Merricourt-Wishek 230 kV	$15,000,000	$14,104,306	MISO SH	Yes
Merricourt-Tatanka North 230 kV	$1,000,000	$1,000,000	MISO SH	Yes
Merricourt-Ellendale 230 kV	$15,000,000	$15,000,000	MISO SH	Yes
1×40 Mvar switched capacitor at Oakes 230 kV (620362)	$2,000,000	$1,628,713	MISO Voltage	Yes
Mandan-J302 POI 230 kV #1	$48,400,000	$48,400,000	MDU LPC	Yes
Prairie-Walle 230 kV	$6,000,000	$2,323,563	MPC	No
Palmyra 345-161 kV xfmr	$9,313,000	$105,000	AECI	No
SPP ERIS Network Upgrades	$21,700,000	$465,966	SPP	Pending
SPP NRIS Network Upgrades	$35,830,140	$176,076	SPP	Pending
Total Cost Per Project for Actual NRIS Elections for each Project		**$166,098,624**		

1.4.13 J1045 Summary

Network Upgrade	Cost	J1045	NUs Type	Self Funding?
1×40 Mvar switched capacitor at Oakes 230 kV (620362)	$2,000,000	$9,901	MISO Voltage	Yes
SPP NRIS Network Upgrades	$35,830,140	$18,588	SPP	Pending
Total Cost Per Project for Actual NRIS Elections for each Project		**$28,489**		

1.4.14 J1050 Summary

Network Upgrade	Cost	J1050	NUs Type	Self Funding?
1×40 Mvar switched capacitor at Oakes 230 kV (620362)	$2,000,000	$31,353	MISO Voltage	Yes
Council Bluffs-S3456 345 kV Terminal Equipment Upgrade	$200,000	$18,345	NRIS	MEC: Yes OPPD: No
SPP NRIS Network Upgrades	$35,830,140	$2,000,000	SPP	Pending
Total Cost Per Project for Actual NRIS Elections for each Project		**$2,049,698**		

1.4.15 J1072 Summary

Network Upgrade	Cost	J1072	NUs Type	Self Funding?
Hazel Creek-Scott Co. 345 kV	$210,829,263	$1,615,550	Base Case NU Hazel Creek-Scott Co. 345 kV	Yes
J1181 POI-Hazleton 345 kV	$600,000	$77,918	MISO SH	MEC: Yes ITCM: Yes
Hazleton-Arnold 345 kV	$1,280,000	$142,038	MISO SH	ITCM: Yes MEC: Yes
Wabaco-Rochester 161 kV	$11,000,000	$0 [1]	MISO SH	Pending
SPP NRIS Network Upgrades	$35,830,140	$74,983	SPP	Pending
Total Cost Per Project for Actual NRIS Elections for each Project		**$1,910,489**		

Note 1: J1072 will assume $1,157,197 cost responsibility if the Wabaco-Rochester 161 kV rebuild is no longer an approved MTEP Appendix A project.

1.4.16 J1084 Summary

Network Upgrade	Cost	J1084	NUs Type	Self Funding?
Nelson;B- Electric JCT;R 345 kV	$36,200,000	$9,770,000	PJM	No
Total Cost Per Project for Actual NRIS Elections for each Project		**$9,770,000**		

1.4.17 J1092 Summary

Network Upgrade	Cost	J1092	NUs Type	Self Funding?
Hazel Creek-Scott Co. 345 kV	$210,829,263	$10,904,962	Base Case NU Hazel Creek-Scott Co. 345 kV	Yes
SPP NRIS Network Upgrades	$35,830,140	$57,759	SPP	Pending
Total Cost Per Project for Actual NRIS Elections for each Project		**$10,962,721**		

1.4.18 J1098 Summary

Network Upgrade	Cost	J1098	NUs Type	Self Funding?
Wilmarth-Field North 345 kV	$96,300,000	$96,300,000	MISO SH	Yes
Field South-Field North 345 kV	$500,000	$500,000	MISO SH	Yes
Second Webster 345/115 kV Transformer	$10,000,000	$10,000,000	NRIS	Yes
SPP NRIS Network Upgrades	$35,830,140	$252,503	SPP	Pending
Total Cost Per Project for Actual NRIS Elections for each Project		**$107,052,503**		

1.4.19 J1105 Summary

Network Upgrade	Cost	J1105	NUs Type	Self Funding?
Hazel Creek-Scott Co. 345 kV	$210,829,263	$4,442,762	Base Case NU Hazel Creek-Scott Co. 345 kV	Yes
Chub Lake 345-115-34.5 kV xfmr	$11,400,000	$11,400,000	MISO SH	No
SPP NRIS Network Upgrades	$35,830,140	$126,630	SPP	Pending
Total Cost Per Project for Actual NRIS Elections for each Project		**$15,969,392**		

1.4.20 J1106 Summary

Network Upgrade	Cost	J1106	NUs Type	Self Funding?
Hazel Creek-Scott Co. 345 kV	$210,829,263	$144,591,717	Base Case NU Hazel Creek-Scott Co. 345 kV	Yes
Lyon Co-Hazel Creek 345 kV	$200,000	$200,000	MISO SH	Yes
1×40 Mvar switched capacitor at Oakes 230 kV (620362)	$2,000,000	$8,251	MISO Voltage	Yes
SPP NRIS Network Upgrades	$35,830,140	$323,611	SPP	Pending
Total Cost Per Project for Actual NRIS Elections for each Project		**$145,123,579**		

1.4.21 J1110 Summary

Network Upgrade	Cost	J1110	NUs Type	Self Funding?
Hazel Creek-Scott Co. 345 kV	$210,829,263	$403,887	Base Case NU Hazel Creek-Scott Co. 345 kV	Yes
Wabaco-Rochester 161 kV	$11,000,000	$0 [1]	MISO SH	Pending
SPP NRIS Network Upgrades	$35,830,140	$4,419,388	SPP	Pending
Total Cost Per Project for Actual NRIS Elections for each Project		**$4,823,275**		

Note 1: J1110 will assume $602,883 cost responsibility if the Wabaco-Rochester 161 kV rebuild is no longer an approved MTEP Appendix A project.

1.4.22 J1122 Summary

Network Upgrade	Cost	J1122	NUs Type	Self Funding?
1×40 Mvar switched capacitor at Oakes 230 kV (620362)	$2,000,000	$36,304	MISO Voltage	Yes
Council Bluffs-S3456 345 kV Terminal Equipment Upgrade	$200,000	$144,859	NRIS	MEC: Yes OPPD: No
Total Cost Per Project for Actual NRIS Elections for each Project		**$181,162**		

1.4.23 J1124 Summary

Network Upgrade	Cost	J1124	NUs Type	Self Funding?
Hazel Creek-Scott Co. 345 kV	$210,829,263	$2,423,325	Base Case NU Hazel Creek-Scott Co. 345 kV	Yes
J1181 POI-Hazleton 345 kV	$600,000	$33,353	MISO SH	MEC: Yes ITCM: Yes
Wabaco-Rochester 161 kV	$11,000,000	$0 [1]	MISO SH	Pending
SPP NRIS Network Upgrades	$35,830,140	$54,356	SPP	Pending
Total Cost Per Project for Actual NRIS Elections for each Project		**$2,511,034**		

Note 1: J1124 will assume $959,873 cost responsibility if the Wabaco-Rochester 161 kV rebuild is no longer an approved MTEP Appendix A project.

1.4.24 J1128 Summary

Network Upgrade	Cost	J1128	NUs Type	Self Funding?
Ellendale-County Line 69 kV	$4,200,000	$4,200,000	MISO SH	Yes
Hayward-County Line 69 kV	$9,700,000	$9,700,000	MISO SH	Yes
Wabaco-Rochester 161 kV	$11,000,000	$0 [1]	MISO SH	Pending
SPP NRIS Network Upgrades	$35,830,140	$7,882,204	SPP	Pending
Total Cost Per Project for Actual NRIS Elections for each Project	**$823,062,263**	**$21,782,204**		

Note 1: J1128 will assume $952,189 cost responsibility if the Wabaco-Rochester 161 kV rebuild is no longer an approved MTEP Appendix A project.

1.4.25 J1131 Summary

Network Upgrade	Cost	J1131	NUs Type	Self Funding?
No Network Upgrades		$0		
Total Cost Per Project for Actual NRIS Elections for each Project		**$0**		

1.4.26 J1132 Summary

Network Upgrade	Cost	J1132	NUs Type	Self Funding?
1×40 Mvar switched capacitor at Oakes 230 kV (620362)	$2,000,000	$3,300	MISO Voltage	Yes
Murray-I35 Tap 69 kV	$1,988,000	$1,988,000	CIPCO	No
Reconductor MCKSBRG-Winterset	$10,000,000	$3,632,406	NRIS	ITCM: Yes MEC: Yes
Council Bluffs-S3456 345 kV Terminal Equipment Upgrade	$200,000	$5,533	NRIS	MEC: Yes OPPD: No
Winterset-Norwalk Structure Replacements	$300,000	$110,414	NRIS	ITCM: Yes MEC: Yes
Total Cost Per Project for Actual NRIS Elections for each Project		**$5,739,653**		

1.4.27 J1135 Summary

Network Upgrade	Cost	J1135	NUs Type	Self Funding?
No Network Upgrades		$0		
Total Cost Per Project for Actual NRIS Elections for each Project		**$0**		

1.4.28 J1140 Summary

Network Upgrade	Cost	J1140	NUs Type	Self Funding?
Hazel Creek-Scott Co. 345 kV	$210,829,263	$27,464,348	Base Case NU Hazel Creek-Scott Co. 345 kV	Yes
M.E. International-Westwood 115 kV	$5,000,000	$5,000,000	MISO SH	XEL: Yes GRE: No
West St. Cloud-Westwood 115 kV	$900,000	$900,000	MISO SH	GRE: No XEL: Yes
STSTPHNT-Fishill 115 kV	$5,100,000	$5,100,000	MISO SH	No
SPP NRIS Network Upgrades	$35,830,140	$52,363	SPP	Pending
Total Cost Per Project for Actual NRIS Elections for each Project		**$38,516,711**		

1.4.29 J1164 Summary

Network Upgrade	Cost	J1164	NUs Type	Self Funding?
1×40 Mvar switched capacitor at Oakes 230 kV (620362)	$2,000,000	$14,851	MISO Voltage	Yes
SPP NRIS Network Upgrades	$35,830,140	$759,941	SPP	Pending
Total Cost Per Project for Actual NRIS Elections for each Project		**$774,792**		

1.4.30 J1169 Summary

Network Upgrade	Cost	J1169	NUs Type	Self Funding?
1×40 Mvar switched capacitor at Oakes 230 kV (620362)	$2,000,000	$11,551	MISO Voltage	Yes
SPP NRIS Network Upgrades	$35,830,140	$1,968,089	SPP	Pending
Total Cost Per Project for Actual NRIS Elections for each Project		**$1,979,640**		

1.4.31 J1174 Summary

Network Upgrade	Cost	J1174	NUs Type	Self Funding?
Webster-Wright 161 kV	$8,000,000	$2,666,667	MISO SH	Yes
Franklin-Wall Lake 161 kV	$12,000,000	$4,000,000	MISO SH	Yes
1×40 Mvar switched capacitor at Oakes 230 kV (620362)	$2,000,000	$4,950	MISO Voltage	Yes
Liberty-Hickory Crk 161 kV	$100,000	$9,959	CIPCO	CIPCO: No
SPP NRIS Network Upgrades	$35,830,140	$8,526,060	SPP	Pending
Total Cost Per Project for Actual NRIS Elections for each Project		**$15,207,636**		

1.4.32 J1175 Summary

Network Upgrade	Cost	J1175	NUs Type	Self Funding?
Webster-Wright 161 kV	$8,000,000	$5,333,333	MISO SH	Yes
Franklin-Wall Lake 161 kV	$12,000,000	$8,000,000	MISO SH	Yes
1×40 Mvar switched capacitor at Oakes 230 kV (620362)	$2,000,000	$13,201	MISO Voltage	Yes
Liberty-Hickory Crk 161 kV	$100,000	$19,918	CIPCO	CIPCO: No
SPP NRIS Network Upgrades	$35,830,140	$8,526,060	SPP	Pending
Total Cost Per Project for Actual NRIS Elections for each Project		**$21,892,512**		

1.4.33 J1181 Summary

Network Upgrade	Cost	J1181	NUs Type	Self Funding?
Hazel Creek-Scott Co. 345 kV	$210,829,263	$1,211,662	Base Case NU Hazel Creek-Scott Co. 345 kV	Yes
J1181 POI-Hazleton 345 kV	$600,000	$332,892	MISO SH	MEC: Yes ITCM: Yes
Hazleton-Arnold 345 kV	$1,280,000	$528,027	MISO SH	ITCM: Yes MEC: Yes
Wabaco-Rochester 161 kV	$11,000,000	$0 [1]	MISO SH	Pending
Wabaco-Alma 161 kV	$6,300,000	$3,005,471	MISO SH	Pending
Liberty-Hickory Crk 161 kV	$100,000	$32,823	CIPCO	CIPCO: No
Nelson;B- Electric JCT;R 345 kV	$36,200,000	$5,920,000	PJM	No
SPP NRIS Network Upgrades	$35,830,140	$80,191	SPP	Pending
Total Cost Per Project for Actual NRIS Elections for each Project		**$11,111,066**		

Note 1: J1181 will assume $3,482,853 cost responsibility if the Wabaco-Rochester 161 kV rebuild is no longer an approved MTEP Appendix A project.

1.4.34 J1187 Summary

Network Upgrade	Cost	J1187	NUs Type	Self Funding?
Merricourt-Wishek 230 kV	$15,000,000	$734,165	MISO SH	Yes
1×40 Mvar switched capacitor at Oakes 230 kV (620362)	$2,000,000	$108,911	MISO Voltage	Yes
Stanton-Leland Olds 230 kV	$2,500,000	$2,500,000	CCS GRE LPC	GRE: No
2nd Coyote 345/115 kV Transformer	$7,000,000	$7,000,000	NRIS	Yes
New Square Butte-Mandan 230 kV Line	$31,000,000	$31,000,000	NRIS	MDU: Yes MPC: No
East Bismark Terminal Upgrades	$100,000	$100,000	NRIS	Yes
Drayton 230-115 kV xfmr 1	$2,100,000	$2,100,000	MPC	No
Prairie-Walle 230 kV	$6,000,000	$3,676,437	MPC	No
SPP ERIS Network Upgrades	$21,700,000	$318,142	SPP	Pending
SPP NRIS Network Upgrades	$35,830,140	$102,960	SPP	Pending
Total Cost Per Project for Actual NRIS Elections for each Project		**$47,640,615**		

1.5 Study Compliance with NERC FAC-002-2 Standard

This DPP 2018 April West Area study was completed in compliance with NERC FAC-002-2:

R1.1: The reliability impact of the new interconnection, or materially modified existing interconnection, on affected system(s).

Section 3 covers summer peak steady-state analysis results which include thermal and voltage constraints impacted by the DPP West Area generating facilities. Thermal and voltage upgrades required to interconnect the new generating facilities are also identified.

Section 4 covers summer shoulder steady-state analysis results which include thermal and voltage constraints impacted by the DPP West Area generating facilities. Thermal and voltage upgrades required to interconnect the new generating facilities are also identified.

Section 5.1 covers reliability impact of the generating facilities per GRE Local planning Criteria (LPC). Network Upgrades required to interconnect the new generating facilities are also identified.

Section 5.2 covers reliability impact of the generating facilities per OTP Local planning Criteria (LPC). Network Upgrades required to interconnect the new generating facilities are also identified.

Section 5.3 covers reliability impact of the generating facilities per MDU Local planning Criteria (LPC). Network Upgrades required to interconnect the new generating facilities are also identified.

Section 6.1 covers reliability impact of the new generating facilities in the CIPCO affected systems.

Section 6.2 covers reliability impact of the new generating facilities in the MPC affected systems.

Section 6.3 covers reliability impact of the new generating facilities in the PJM affected systems.

Section 6.4 covers reliability impact of the new generating facilities in the AECI affected systems.

Section 6.5 covers reliability impact of the new generating facilities in the SPP affected systems.

Section 7 covers transient stability analysis results.

Section 8 covers voltage stability (PV) analysis on the MWEX System Operating Limit (SOL). Network Upgrades required for MWEX voltage stability are identified.

Section 9 covers short circuit reliability impact of the new generating facilities.

Section 10 covers Deliverability reliability impact of the new NRIS generating facilities.

R1.2: Adherence to applicable NERC Reliability Standards; regional and Transmission Owner planning criteria; and Facility interconnection requirements.

Sections 2.2-2.4, Section 5, Section 6, and Section 7 all cover NERC Reliability Standard TPL-001-4.

Section 5.1 covers GRE Local Planning Criteria (LPC).

Section 5.2 covers OTP LPC.

Section 5.3 covers MDU LPC.

Section 6.1 covers CIPCO system planning criteria.

Section 6.2 covers MPC system planning criteria.

Section 6.3 covers PJM system planning criteria.

Section 6.4 covers AECI system planning criteria.

Section 6.5 covers SPP system planning criteria.

Section 8 (voltage stability analysis) covers individual system planning criteria (ATC).

Section 10 covers MISO system planning criteria.

R1.3: Steady-state, short-circuit, and dynamics studies, as necessary, to evaluate system performance under both normal and contingency conditions.

Section 3 and Section 4 cover MISO steady-state assessment including NERC category P0 to P7 contingencies (TPL-001-4).

Section 5.1 covers GRE's LPC assessment including NERC category P0 to P7 contingencies (TPL-001-4).

Section 5.2 covers OTP's LPC assessment including NERC category P0 to P7 contingencies (TPL-001-4).

Section 5.3 covers MDU's LPC assessment including NERC category P0 to P7 contingencies (TPL-001-4).

Section 6.1 covers CIPCO steady-state assessment including NERC category P0 to P7 contingencies (TPL-001-4).

Section 6.2 covers MPC steady-state and transient stability assessment including NERC category P0 to P7 contingencies (TPL-001-4).

Section 6.3 covers PJM steady-state assessment including NERC category P0 to P7 contingencies (TPL-001-4).

Section 6.4 covers AECI steady-state assessment including NERC category P0 to P7 contingencies (TPL-001-4).

Section 6.5 covers SPP steady-state assessment including NERC category P0 to P7 contingencies (TPL-001-4).

Section 7 covers transient stability studies under NERC category P0 to P7 contingencies (TPL-001-4).

Section 8 covers steady-state voltage stability assessment.

Section 9 covers short circuit assessment.

Section 10 covers MISO deliverability study (steady-state assessment) including NERC category P0 to P1 contingencies (TPL-001-4).

R1.4: Study assumptions, system performance, alternatives considered, and coordinated recommendations. While these studies may be performed independently, the results shall be evaluated and coordinated by the entities involved.

Section 2.1, Section 2.2, Section 2.3, and Section 2.4, Section 7.2, Section 7.3, and Section 7.4 cover study assumptions and system performance criteria.

Jointly coordinated recommendations can be found in Section 5.1 (MISO and GRE), Section 5.2 (MISO and OTP), Section 5.3 (MISO and MDU), Section 6.1 (MISO and CIPCO), Section 6.2 (MISO and MPC), Section 6.3 (MISO and PJM), Section 6.4 (MISO and AECI), Section 6.5 (MISO and SPP), and Section 8 (MISO and ATC). Results in Sections 3, 4, 5, 6, 7, 9 and 10 have also been reviewed by PJM, SPP, AECI, CIPCO, MPC, and ATC.

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Section

1

Introduction

Thirty-four (34) generation projects, listed in Table A-1 (Appendix A.1), have requested to interconnect to the MISO transmission network in the West Area and have advanced to the Definitive Planning Phase (DPP) 2018 April Phase 2 study (DPP West Area). J952 and J975 have requested Energy Resource Interconnection Service (ERIS); J953 and J954 have requested external Network Resource Interconnection Service (external NRIS); All other generating facilities have requested both ERIS and NRIS.

This report presents the study results of a System Impact Study (SIS) performed to evaluate the interconnection of the generating facilities in the DPP West Area Phase 2 study.

The study was performed under the direction of MISO by Siemens PTI and an ad hoc study group. The ad hoc study group was formed to review the study scope, methodology, models, and results. The ad hoc study group consisted of representatives from the interconnection customers and the following utility companies – Ameren, American Transmission Company, Basin Electric Power, Cedar Falls Utilities, Central Iowa Power Cooperative, City of Springfield (IL) Water Light & Power, Columbia (MO) Water and Light, Commonwealth Edison, Corn Belt Power Cooperative, Dairyland Power, Great River Energy, ITC Midwest, Lincoln Electric System, Manitoba Hydro, MidAmerican Energy Company, MISO, Minnesota Power, Minnkota Power, Missouri River Energy Services, Montana-Dakota Utilities Co., Muscatine Power & Water, Nebraska Public Power District, Northwestern Public Service, Omaha Public Power District, Otter Tail Power, PJM, Southern Illinois Power Cooperative, Southern Minnesota Municipal Power Agency, SPP, Western Area Power Administration, and Xcel Energy.

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Section 2

Model Development and Study Criteria

2.1 Model Development

2.1.1 Benchmark Cases

DPP 2018 April West area power flow benchmark cases representing 2024 summer shoulder and summer peak conditions were developed from the MTEP19 models with LBA dispatch.

The benchmark cases for DPP 2018 April study were created as follows:

- MISO prior queued generation projects were modeled, and their associated Network Upgrades (NU) prior to DPP 2017 August cycle were also modeled. Network Upgrades required in DPP 2017 August West Area Phase 2 were not modeled since the study has not been completed yet.
- DPP 2018 April generation projects in the West Area (DPP West Area, Table A-1), Central Area (Table A-3), Michigan Area (Table A-4), and ATC Area (Table A-5) were modeled with offline status.
- For MISO generation projects, their output was sunk to the MISO North (Appendix A.3, Table A-7), where generation was scaled uniformly;
- PJM generation projects were modeled and dispatched. The generation output was sunk to the PJM market (Appendix A.4, Table A-8), where generation was scaled uniformly.
- SPP generation projects were modeled and dispatched. The generation output was sunk to the SPP market (Appendix A.5, Table A-9), where generation was scaled uniformly. The Network Upgrades identified in the SPP DIS2016-001 and DIS2016-002 studies were also modeled.
- Models were further reviewed by the Ad Hoc study members (transmission owners and customers). Model corrections and changes were made based on the comments and feedback. These modeling changes are listed in Appendix A.2.
- Adjusted Square Butte DC to match the total output of the Bison (Bison 1 to 5) and Oliver County (Oliver County 1 and 2) wind farms.
- Adjusted CU DC to match the total output of Coal Creek generation units #1 and #2.
- MHEX interface transfer level is at 1530 MW in summer shoulder and 1800 MW in summer peak cases.

2.1.2 Study Cases

Summer peak study case was created by dispatching the DPP 2018 April generation projects at the specified summer peak level from the benchmark case.

Summer shoulder study case was created by dispatching the DPP 2018 April generation projects at the specified summer shoulder level from the benchmark case.

The MISO North was used for power balance, where generation was scaled uniformly.

Due to voltage collapse under system intact condition in both study and benchmark summer shoulder cases, two (2) fictitious large size SVCs in SPP area (Table 2-1) were added to the summer shoulder study and benchmark cases to achieve converged power flow thermal solutions.

Table 2-1: Fictitious SVCs Added Only in Summer Shoulder Case

Location	Bus #	SVC Mvar
Post Rock 345 kV	530583	500
Mingo 345 kV	531451	400

Both study and benchmark power flow cases were solved with transformer tap adjustment enabled, area interchange disabled, phase shifter adjustment enabled and switched shunt adjustment enabled.

The interface transfer levels in the 2024 study cases are summarized in Table 2-2.

Table 2-2: Interface Transfer Levels in 2024 Study Cases

Interface	2024 SH Case (MW)	2024 SPK Case (MW)
MHEX	1531	1799
MWEX	1294.4	372.4
Arrowhead PST	517.0	0.2
J732 POI – Stone Lake 345 kV	749.0	511.5

2.2 Contingency Criteria

A variety of contingencies were considered for steady-state analysis:

- NERC Category P0 with system intact (no contingencies)
- NERC Category P1 contingencies
    - NERC Category P1 contingencies, at buses with a nominal voltage of 69 kV and above, in the following areas: CWLD (area 333), AMMO (area 356), AMIL (area 357), CWLP (area 360), SIPC (area 361), WEC (area 295), WEC MI (area 296), XCEL (area 600), MP (area 608), SMMPA (area 613), GRE (area 615), OTP (area 620), ITCM (area 627), MPW (area 633), MEC (area 635), MDU (area 661), BEPC-MISO (area 663), MHEB (area 667), DPC (area 680), ALTE (area 694), WPS (area 696), MGE (area 697), UPPC (area 698), CE(area 222), NPPD (area 640), OPPD (area 645), LES (area 650), WAPA (area 652), BEPC-SPP (area 659), AECI (area 330), MIPU(area 540), KCPL (area 541), KACY (area 542), INDN (area 545).

- Multiple-element NERC Category P1 contingencies, in Dakotas, Illinois, Iowa, Minnesota, Missouri, and Wisconsin. These specified Category P1 contingencies are listed in Appendix A.6.
- NERC Category P2-P7 contingencies
  - Selected NERC Category P2-P7 contingencies provided by the Ad Hoc Study Group, in the study region of Dakotas, Illinois, Iowa, Minnesota, Missouri, and Wisconsin. These specified Category P2-P7 contingencies are listed in Appendix A.6.

For all contingency and post-disturbance analyses, cases were solved with transformer tap adjustment enabled, area interchange adjustment disabled, phase shifter adjustment disabled (fixed) and switched shunt adjustment enabled.

2.3 Monitored Elements

The study area is defined in Table 2-3. Facilities in the study area were monitored for system intact and contingency conditions. Under NERC category P0 conditions (system intact) branches were monitored for loading above the normal (PSS®E rate A) rating. Under NERC category P1-P7 conditions, branches were monitored for loading as shown in the column labeled "Post-Disturbance Thermal Limits".

Table 2-3: Monitored Elements

Owner / Area	Monitored Facilities	Thermal Limits [1]		Voltage Limits [2]	
		Pre-Disturbance	Post-Disturbance	Pre-Disturbance	Post-Disturbance
AECI	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90
AMIL	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.075/0.90
AMMO	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.075/0.90
ATCLLC	69 kV and above	95% of Rate A	95% of Rate B	1.05/0.95	1.10/0.90
BEPC-MISO	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90
BEPC-SPP	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90
CBPC	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90
CMMPA	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.07/0.90
CWLD	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90
CWLP	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.075/0.90

Owner / Area	Monitored Facilities	Thermal Limits [1]		Voltage Limits [2]	
		Pre-Disturbance	Post-Disturbance	Pre-Disturbance	Post-Disturbance
CE	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90
DPC	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90
GMO	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90
GRE	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.92/0.90
INDN	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90
ITCM	69 kV and above	100% of Rate A	100% of Rate B	1.07/1.05/0.95	1.10/0.93
KACY	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90
KCPL	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90
LES	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90
MDU	57 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90
MEC	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.96/0.95	1.05/0.96/0.95/0.94/ 0.93[3]
MHEB	69 kV and above	100% of Rate A	100% of Rate B	1.12/1.1/1.07/1.05/1.04 / 0.99/0.97/0.96/0.95	1.15/1.10/0.94/0.90
MP	69 kV and above	100% of Rate A	100% of Rate B	1.05/1.00	1.10/0.95
MPC	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.97	1.10/0.92
MPW	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.06/0.92
MRES	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.97	1.05/0.92
NPPD	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90
OPPD	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90

Owner / Area	Monitored Facilities	Thermal Limits [1]		Voltage Limits [2]	
		Pre-Disturbance	Post-Disturbance	Pre-Disturbance	Post-Disturbance
OTP	40 kV and above	100% of Rate A	100% of Rate B	1.07/1.05/0.97	1.10/0.92
PPI	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.075/0.90
RPU	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.92
SIPC	69 kV and above	100% of Rate A	100% of Rate B	1.07/0.95	1.09/0.91
SMMPA	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90
WAPA	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.10/0.90
WPPI	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.1/0.9
XEL	69 kV and above	100% of Rate A	100% of Rate B	1.05/0.95	1.05/0.92

Notes

1: PSS®E Rate A, Rate B or Rate C

2: Limits dependent on nominal bus voltage

3: For facilities in Cedar Falls Utilities or Ames Municipal Utilities, post-contingency voltage limits are 1.05/0.94 for >200 kV, and 1.05/0.93 for others.

2.4 Performance Criteria

A branch is considered as a thermal injection constraint if the branch is loaded above its applicable normal or emergency rating for the post-change case, and any of the following conditions are met:

1) the generator (NR/ER) has a larger than 20% DF on the overloaded facility under post contingent condition or 5% DF under system intact condition, or
2) the megawatt impact due to the generator is greater than or equal to 20% of the applicable rating (normal or emergency) of the overloaded facility, or
3) the overloaded facility or the overload-causing contingency is at generator's outlet, or
4) for any other constrained facility, where none of the study generators meet one of the above criteria in 1), 2), or 3), however, the cumulative megawatt impact of the group of study generators (NR/ER) is greater than 20% of the applicable rating, then only those study generators whose individual MW impact is greater than 5% of the applicable rating and has DF greater than 5% (OTDF or PTDF) will be responsible for mitigating the cumulative MW impact constraint.

A bus is considered a voltage constraint if both of the following conditions are met. All voltage constraints must be resolved before a project can receive interconnection service.

1) the bus voltage is outside of applicable normal or emergency limits for the post-change case, and
2) the change in bus voltage is greater than 0.01 per unit.

All DPP 2018 April West Area study generators must mitigate thermal injection constraints and voltage constraints to obtain unconditional Interconnection Service.

Further, all generators requesting Network Resource Interconnection Service (NRIS) must mitigate constraints found by using the deliverability algorithm, to meet the system performance criteria for NERC category P0-P1 events, if the constraint demonstrates an incremental flow caused by the generator equal to or greater than 5% of the generator’s maximum dispatch level in each case.

2.5 Reactive Power Requirements for Non-Synchronous Generation (FERC Order 827)

For non-synchronous generation projects in the DPP 2018 April West Area study group, if they do not have signed Generator Interconnection Agreement (GIA) or Provisional GIA (PGIA) by September 21, 2016, they are required to provide dynamic reactive power within the range of 0.95 leading to 0.95 lagging at the high-side of the generator substation.

All non-synchronous generation projects in this study group are required to meet the reactive power requirements per FERC Order 827.

Collector system and shunt compensation of DPP West projects are modeled, which are listed in Appendix A.1, Table A-2. An analysis was performed to study the reactive power requirements (FERC Order 827) for the non-synchronous generation projects in the DPP 2018 April West study group. The analysis was performed as follows:

Step 1: Verify whether total dynamic reactive power (reactive power from generators and dynamic compensation devices) in the plant can meet the dynamic reactive power range of 0.95 leading to 0.95 lagging at the generator terminal bus. The verification in Step 1 was performed when generator data was submitted and modeled.

Step 2: Verify whether total reactive power (reactive power from generators, dynamic compensation devices, and static compensation devices) in the plant can meet the dynamic reactive power range of 0.95 leading to 0.95 lagging at the high-side of the generator substation. The testing procedure in Step 2 is described in the following:

- Lock the high-side of the generator substation at 1.0 pu voltage by adding a fictitious SVC. This is to ensure that the test result is not affected by the system condition.
- Lock the reactive power output of the generator to the maximum limit (Qmax). Make sure all shunt compensation devices within the substation are at the maximum capacitive output. Adjust transformer tap to ensure bus voltages within the substation are within 0.95 – 1.05 pu range. Measure real power and reactive power from the generator plant to the high-side of the generator substation. Calculate the power factor to verify if it meets the 0.95 lagging requirement.
- Lock the reactive power output of the generator to the minimum limit (Qmin). Make sure all shunt compensation devices within the substation are at the maximum inductive output. Adjust transformer tap to ensure bus voltages within the substation

are within 0.95 – 1.05 pu range. Measure real power and reactive power from the generator plant to the high-side of the generator substation. Calculate the power factor to verify if it meets the 0.95 leading requirement.

Appendix C lists reactive power requirement analysis results for the DPP West generation projects. The results are summarized as following:

- J959, J981, J982, J1024, J1072, J1084, J1105, J1106, J1110, J1124, J1128, J1164, and J1187 do not meet the reactive power requirements per FERC Order 827.
- All other non-synchronous generation projects can meet the reactive power requirements per FERC Order 827.

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Section

3

Summer Peak Steady-State Analysis

Summer peak steady-state analysis was performed in summer peak scenario to identify thermal and voltage upgrades required for interconnecting the generating facilities in the DPP 2018 April West Area group to the transmission system.

3.1 Study Procedure

3.1.1 Computer Programs

Steady-state analyses were performed using PSS®E version 33.12.1 and PSS®MUST version 12.4.0.

3.1.2 Study Methodology

Summer peak power flow cases were created in the procedure as described in Section 2.1. The summer peak study case can converge under post-contingency conditions. Therefore, no fictitious SVCs or Base Case Network Upgrades (BCNUs) were modeled in the summer peak cases. Nonlinear (AC) contingency analysis was performed on the benchmark and study cases, and the incremental impact of the DPP West Area generating facilities was evaluated by comparing the steady-state performance of the transmission system in the benchmark and study cases. Network upgrades were identified to mitigate any summer peak constraints.

3.2 Contingency Analysis Results for Summer Peak Condition

The incremental impact of the proposed interconnection on individual facilities was evaluated by comparing flows and voltages between benchmark case (without DPP 2018 April projects) and study case (with DPP 2018 April projects).

3.2.1 System Intact Conditions

For NERC category P0 (system intact) conditions, no thermal constraints (Table D-1) or voltage constraints (Table D-2) were identified.

3.2.2 Post Contingency Conditions

The results in this Section are for analysis of conditions following NERC Category P1-P7 contingencies. All category P1 contingencies were converged.

For P1 contingencies, no thermal constraints (Table D-3) or voltage constraints (Table D-4) were identified.

Two category P2-P7 contingencies (Table D-7) were not converged, and their dc thermal results are listed in Table D-8. The contingency was not converged in the benchmark or study cases. No mitigation plan is required for the study projects for these contingencies.

For P2-P7 contingencies, thermal constraints are listed in Table D-5, and no voltage constraints were identified (Table D-6).

3.3 Summer Peak Worst Thermal Constraints

Table 3-1 lists worst thermal constraints and Network Upgrades in the 2024 summer peak scenario.

Table 3-1: 2024 Summer Peak Thermal Constraints and Network Upgrades, Maximum Screened Loading

Generator	Constraint	Rating	Owner	Worst Loading		Contingency	Cont Type	Mitigation	Cost ($)
				(MVA)	(%)				
J975	Sheyenne-Mapleton 115 kV	182.1	XEL OTP	224.8	123.5	CEII Redacted	P2-P7	Sheyenne-Mapleton 115 kV Rebuild. NU in DPP 2017 Aug West Ph2	$0

3.4 Network Upgrades Identified in MISO ERIS Analysis for 2024 Summer Peak Scenario

Based on the MISO 2024 summer peak steady state analyses, no MISO thermal NUs or reactive power NUs are required for DPP 2018 April West projects.

It should be noted that if projects in DPP 2017 August West Phase 2 study are withdrawn, responsibilities of some NUs required in DPP 2017 Aug. West Phase 2 study will fall onto the projects in DPP 2018 April cycle.

Section

4

Summer Shoulder Steady-State Analysis

Summer shoulder steady-state analysis was performed in summer shoulder scenario to identify thermal and voltage upgrades required for interconnecting the generating facilities in the DPP 2018 April West Area group to the transmission system.

4.1 Study Procedure

Summer shoulder power flow case was created in the procedure as described in Section 2.1. Due to post-contingent voltage collapse and thermal overloads in the initial power flow case, steady-state analysis was performed in the following three-step procedure:

- Step 1: Non-linear (AC) contingency analysis (Stage-1 ACCC) was performed for single critical contingencies (contingencies in ≥200 kV system in MISO West area) to identify voltage collapse and thermal overloads.
- Step 2: Based on the identified voltage collapse and thermal overloads in the Stage-1 ACCC, project justification analysis was performed to determine Network Upgrades (NUs) required for interconnection of DPP West projects. These selected NUs are called Base Case NUs.
- Step 3: The Base Case NUs were added to the models. Stage-2 ACCC was performed to identify any remaining thermal and voltage constraints.

4.2 Step 1 – Stage-1 ACCC Analysis

AC contingency analysis was performed for single critical contingencies (contingencies in ≥200 kV system in MISO West area) to identify voltage collapse and thermal overloads. Analysis was performed in the 2024 summer shoulder scenario using PSS®E.

4.2.1 Stage-1 Voltage Violations

One single critical contingency (contingencies in ≥200 kV system in MISO West area) was not converged (Table E-1). Potential voltage collapses (voltage <0.87 p.u.) are listed in Table E-2. Voltage violations (voltage < Vlow limit and voltage ≥0.87 p.u.) are listed in Table E-3. The potential voltage collapses were identified in the following areas:

- Lyon Co-Cedar Mountain-Helena-Chub Lake 345 kV
- Lyon Co-Hazel Creek 345 kV
- Helena-Sheas Lake 345 kV
- Jamestown-Buffalo-Bison-Maple River 345 kV
- Alexandria-Riverview-Quarry 345 kV

- Hazel Creek-Minn Valley Tap 230 kV
- Prairie-Walle-Winger-Cass Lake 230 kV
- Jamestown-Pickert-Grand Forks 230 kV
- Jamestown-Fargo-Moorhead-Morris 230 kV
- Pillsbury-Maple River-Frontier-Wahpeton 230 kV
- J897 POI-J628 POI 230 kV
- Big Stone-Blair 230 kV
- Panther-McLeod-Blue Lake 230 kV
- Appledorn-Granite Falls-Willmar-Paynesville 230 kV
- Sheyenne-Lake Park-Audubon-Erie Jct.-Hubbard-Badoura 230 kV
- Oakes-Forman-Hankinson-Wahpeton-Fergus Falls-Silver Lake-Henning-Inman-Wing River-Riverton-Mud Lake 230 kV

4.2.2 Stage-1 Thermal Violations

Thermal violations are listed in Table E-4. The following 345 kV lines were heavily loaded to more than 1400 MVA. A typical 345 kV line has Surge Impedance Loading (SIL) around 400 MVA. A transmission line absorbs reactive power from system quadratically proportional to line current when line flow is more than its SIL.

- Wilmarth-Sheas Lake-Helena-Chub Lake 345 kV
- Scott Co-Blue Lake 345 kV
- Crandal-Fieldon-Wilmarth 345 kV

4.3 Step 2 – Base Case NUs Justification Analysis

Based on the identified potential voltage collapse and voltage violations in the Stage-1 ACCC and the identified heavily overloaded 345 kV lines under post-contingent conditions, various transmission Network Upgrades (NUs) were tested. The Hazel Creek-Scott County 345 kV line was justified as Base Case NU due to the following performance advantages:

1) The new line carries 754 MVA significant flow under system intact condition.

2) The new line can effectively mitigate voltage collapse caused by the following contingencies:

    - Wilmarth-Sheas Lake 345 kV
    - Helena-Sheas Lake 345 kV
    - Helena-Scott County 345 kV
    - Brookings Co-Astoria 345 kV
    - Heskett-J302 POI 230 kV

3) The new line can greatly improve voltages systemically.

4) The previously identified non-converged contingency Heskett-J302 POI 230 kV line will be converged with addition of the new line.

5) The new line can mitigate or significantly reduce the following identified thermal overloads:

- Wilmarth-Sheas Lake-Helena-Chub Lake 345 kV
- Minn. Valley-Panther-McLeod 230 kV
- Granite Falls-Willmar 230 kV
- Lakefield-Crandal-Fieldon 345 kV
- Helena-Scott Co 345 kV
- Hankinson-Wahpeton-Fergus Falls-Silver Lake-Henning-Inman-Wing River 230 kV
- Split Rock-White 345 kV

The Hazel Creek-Scott County 345 kV Base Case NU justification analysis was performed based on the Stage-1 ACCC results. Detailed justification results are in Appendix E.2.

Potential voltage collapse was also identified under the contingency of "Twin Brooks-Big Stone South 345 kV line. A 2nd 345 kV line Twin Brooks-Big Stone South will mitigate this issue. This 2nd line is also required in DPP 2017 August West Phase 2 study.

Severe thermal overloads were identified under the contingency of "J602 POI-Prairie 230 kV line". The overloads can be mitigated by adding a 2nd 230 kV line J602 POI-Prairie. This 2nd line is also required in DPP 2017 August West Phase 2 study.

In summary, one justified Base Case NU and two DPP 2017 August Phase 2 NUs (Table 4-1) are required for mitigating potential voltage collapse and severe thermal overloads identified in the Stage-1 ACCC analysis.

Table 4-1: Network Upgrades Required for Mitigating Voltage Collapse and Severe Thermal Overloads

NUs	Needs	Miles	Cost ($)
Hazel Creek-Scott County 345 kV	Base Case NU	115	$210,829,263
Big Stone South-Twin Brooks 345 kV 2nd Circuit	DPP 2017 Aug. Ph2 NU	30.25	$54,500,000
New J628 POI– Prairie 230 kV 2nd Circuit	DPP 2017 Aug. Ph2 NU	11	$22,360,000

4.4 Step 3 – Stage-2 ACCC Analysis

The Hazel Creek-Scott County 345 kV Base Case NU, 2nd circuit of Big Stone South-Twin Brooks 345 kV, and 2nd circuit J628 POI-Prairie 230 kV were added to create Stage-2 models. AC contingency analysis was performed in the Stage-2 models to identify any remaining thermal and voltage constraints.

4.4.1 Stage-2 ACCC Analysis Results for Summer Shoulder Condition

4.4.1.1 System Intact Conditions

For NERC category P0 (system intact) conditions, thermal constraints are listed in Table E-8. No voltage constraints were identified (Table E-9).

4.4.1.2 Post Contingency Conditions

The results in this Section are for analysis of conditions following NERC Category P1-P7 contingencies. All NERC Category P1 contingencies were converged.

For P1 contingencies, thermal constraints are listed in Table E-10, and voltage constraints are listed in Table E-11.

There are five P2-P7 contingencies (Table E-14) not converged in the benchmark case but converged in the study case. These contingencies were not converged in the benchmark case due to voltage collapse in the areas of Coal Creek, Lyon County, and Twin Cities. No mitigation plan is required for the study projects because these contingencies were converged in the study case.

Two category P2-P7 contingencies (Table E-14) were not converged in both the benchmark and study cases. No mitigation plan is required for the study projects for these non-converged contingencies.

For the non-converged contingencies in Table E-14, DC contingency analysis was performed to get the dc thermal results. The dc thermal results for non-converged contingencies are listed in Table E-15.

For P2-P7 contingencies, thermal constraints are listed in Table E-12, and voltage constraints are listed in Table E-13.

4.4.2 Summer Shoulder Worst Thermal Constraints in the Stage-2 ACCC

Table 4-2 lists worst thermal constraints and Network Upgrades identified in the Stage-2 ACCC for 2024 summer shoulder scenario.

Table 4-2: 2024 Summer Shoulder Thermal Constraints, Maximum Screened Loading, Stage-2 ACCC

Generator	Constraint	Rating	Owner	Worst Loading (MVA)	Worst Loading (%)	Contingency	Cont Type	Mitigation
J1024	J1024 POI-Clarinda 161 kV	257.0	MEC	286.7	111.5	CEII Redacted	P1	MEC: substation terminal equipment upgrades. New rating predicted to be 410 MVA.
J1024	J1024 POI-Clarinda 161 kV	257.0	MEC	286.6	111.5	CEII Redacted	P2-P7	MEC: substation terminal equipment upgrades. New rating predicted to be 410 MVA.
J967,J1072,J1124,J1181	J1181 POI-Hazleton 345 kV	872.0	MEC ITCM	960.9	110.2	CEII Redacted	P1	MEC: MEC owns portion of line conductor. Structure replacements. New MEC Only rating expected to be 1094/1094 MVA. $600,000 ITCM: ITCM records show a rating of 1006 MVA summer. $0
J967,J1072,J1124,J1181	J1181 POI-Hazleton 345 kV	872.0	MEC ITCM	1026.7	117.7	CEII Redacted	P2-P7	MEC: MEC owns portion of line conductor. Structure replacements. New MEC Only rating expected to be 1094/1094 MVA. $600,000 ITCM: ITCM records show a rating of 1006 MVA summer. $0
J1024	J611 POI-Maryville 161 kV	152.0	MEC GMO	254.0	167.1	CEII Redacted	P0	MEC: Existing MEC only rating expected to be 410 MVA after DPP 2016 AUG West line reconductor network upgrade. GMO: NU is not required unless it is identified as constraint in affected system study.

Generator	Constraint	Rating	Owner	Worst Loading		Contingency	Cont Type	Mitigation
				(MVA)	(%)			
J1024	J611 POI-Maryville 161 kV	171.0	MEC GMO	294.1	172.0	CEII Redacted	P1	MEC: Existing MEC only rating expected to be 410 MVA after DPP 2016 AUG West line reconductor network upgrade. GMO: NU is not required unless it is identified as constraint in affected system study.
J1024	J611 POI-Maryville 161 kV	171.0	MEC GMO	300.0	175.4	CEII Redacted	P2-P7	MEC: Existing MEC only rating expected to be 410 MVA after DPP 2016 AUG West line reconductor network upgrade. GMO: NU is not required unless it is identified as constraint in affected system study.
J982	J720 POI-Lakefield 345 kV	864.0	ITCM	893.6	103.4	CEII Redacted	P1	ITCM records show a rating of 932 MVA summer limit due to MEC facilities.
J982	J720 POI-Lakefield 345 kV	864.0	ITCM	893.5	103.4	CEII Redacted	P2-P7	ITCM records show a rating of 932 MVA summer limit due to MEC facilities.
J975,J1040,J1187	G16-017 Tap-Ft. Thompson 345 kV	717.0	WAPA	750.8	104.7	CEII Redacted	P0	NU is not required unless it is identified as constraint in affected system study.

Generator	Constraint	Rating	Owner	Worst Loading		Contingency	Cont Type	Mitigation
				(MVA)	(%)			
J1098	Wilmarth-Field North 345 kV	1493.9	XEL	1495.1	100.1	CEII Redacted	P2-P7	Fieldon-Wilmarth 345 rebuild
J1098	Wilmarth-Sheas Lake 345 kV	1515.8	XEL	1540.6	101.6	CEII Redacted	P1	Wilmarth-Sheas Lake 345 kV Rebuild. NU in DPP 2017 Aug West Ph2
J1098	Wilmarth-Sheas Lake 345 kV	1515.8	XEL	1718.3	113.4	CEII Redacted	P2-P7	Wilmarth-Sheas Lake 345 kV Rebuild. NU in DPP 2017 Aug West Ph2
J1106	Split Rock-White 345 kV	717.1	XEL WAPA	866.2	120.8	CEII Redacted	P2-P7	XEL: Limiter is on WAPA facility. $0 WAPA: NU is not required unless it is identified as constraint in affected system study.
J982,J1001,J1045,J1098, J1106,J1164,J1169	Blue Lake-Scott Co 345 kV	1378.0	XEL	1555.7	112.9	CEII Redacted	P0	Blue Lake-Scott County 345 kV Rebuild. NU in DPP 2017 Aug West Ph2
J982,J1001,J1024,J1045, J1106,J1122,J1164,J1174, J1175	Blue Lake-Scott Co 345 kV	1515.8	XEL	2229.0	147.0	CEII Redacted	P1	Blue Lake-Scott County 345 kV Rebuild. NU in DPP 2017 Aug West Ph2

Generator	Constraint	Rating	Owner	Worst Loading		Contingency	Cont Type	Mitigation
				(MVA)	(%)			
J1106	Blue Lake-Scott Co 345 kV	1515.8	XEL	2199.2	145.1	CEII Redacted	P2-P7	Blue Lake-Scott County 345 kV Rebuild. NU in DPP 2017 Aug West Ph2
J1098	Field South-Field North 345 kV	1493.9	XEL	1494.2	100.0	CEII Redacted	P2-P7	bypassing the Fieldon series cap
J1098	Field South-Crandal 345 kV	1332.6	XEL	1422.9	106.8	CEII Redacted	P1	Crandal-Fieldon 345 kV Rebuild. NU in DPP 2017 Aug West Ph2
J1098,J1164	Field South-Crandal 345 kV	1332.6	XEL	1494.6	112.2	CEII Redacted	P2-P7	Crandal-Fieldon 345 kV Rebuild. NU in DPP 2017 Aug West Ph2
J1106	Lyon Co-Hazel Creek 345 kV	1314.6	XEL	1382.6	105.2	CEII Redacted	P2-P7	Upgrade some sub equipment at Hazel that would put the rating to 1790 MVA normal and emergency
J982,J1024,J1045,J1050, J1098,J1122,J1132,J1164, J1174,J1175	Helena-Sheas Lk 345 kV	1195.1	XEL	1244.8	104.2	CEII Redacted	P0	Helena-Sheas Lake 345 kV Rebuild. NU in DPP 2017 Aug West Ph2
J982,J1024,J1050,J1098, J1128,J1169,J1174,J1175	Helena-Sheas Lk 345 kV	1195.1	XEL	1517.7	127.0	CEII Redacted	P1	Helena-Sheas Lake 345 kV Rebuild. NU in DPP 2017 Aug West Ph2

Generator	Constraint	Rating	Owner	Worst Loading		Contingency	Cont Type	Mitigation
				(MVA)	(%)			
J982,J1098,J1174,J1175	Helena-Sheas Lk 345 kV	1195.1	XEL	1710.4	143.1	CEII Redacted	P2-P7	Helena-Sheas Lake 345 kV Rebuild. NU in DPP 2017 Aug West Ph2
J975	Sheyenne-Lake Park 230 kV	301.0	XEL MPC OTP	356.8	118.5	CEII Redacted	P0	Sheyenne-Lake Park 230 kV Uprate. NU in DPP 2017 Aug West Ph2
J975,J1040,J1187	Sheyenne-Lake Park 230 kV	301.0	XEL MPC OTP	363.4	120.7	CEII Redacted	P1	Sheyenne-Lake Park 230 kV Uprate. NU in DPP 2017 Aug West Ph2
J975	Sheyenne-Mapleton 115 kV	182.1	XEL OTP	310.9	170.7	CEII Redacted	P1	Sheyenne-Mapleton 115 kV Rebuild. NU in DPP 2017 Aug West Ph2
J975	Sheyenne-Mapleton 115 kV	182.1	XEL OTP	312.9	171.8	CEII Redacted	P2-P7	Sheyenne-Mapleton 115 kV Rebuild. NU in DPP 2017 Aug West Ph2
J1140	M.E. International-Westwood 115 kV	246.7	XEL GRE	269.0	109.0	CEII Redacted	P1	XEL: Rebuild ME International to Westwood tap (2.1 miles) with 795 ACSS conductor and replace line switches. $5,000,000 GRE: XEL facility

Generator	Constraint	Rating	Owner	Worst Loading		Contingency	Cont Type	Mitigation
				(MVA)	(%)			
J1140	M.E. International-Westwood 115 kV	246.7	XEL GRE	271.4	110.0	CEII Redacted	P2-P7	XEL: Rebuild ME International to Westwood tap (2.1 miles) with 795 ACSS conductor and replace line switches. $5,000,000 GRE: XEL facility
J1128	Austin-Murphy 161 kV	331.3	SMMPA	336.3	101.5	CEII Redacted	P1	Austin-Murphy Creek 161 kV Rebuild. NU in DPP 2017 Aug West Ph2
J1128	Austin-Murphy 161 kV	331.3	SMMPA	375.2	113.3	CEII Redacted	P2-P7	Austin-Murphy Creek 161 kV Rebuild. NU in DPP 2017 Aug West Ph2
J1128	Murphy-J1128 POI 161 kV	276.0	SMMPA	276.3	100.1	CEII Redacted	P0	Murphy Creek – Hayward 161 kV Rebuild. NU in DPP 2017 Aug West Ph2

Generator	Constraint	Rating	Owner	Worst Loading		Contingency	Cont Type	Mitigation
				(MVA)	(%)			
J1128	Murphy-J1128 POI 161 kV	276.0	SMMPA	356.2	129.0	CEII Redacted	P1	Murphy Creek – Hayward 161 kV Rebuild. NU in DPP 2017 Aug West Ph2
J1128	Murphy-J1128 POI 161 kV	276.0	SMMPA	395.9	143.4	CEII Redacted	P2-P7	Murphy Creek – Hayward 161 kV Rebuild. NU in DPP 2017 Aug West Ph2
J975	Hubbard-Badoura 230 kV	187.0	MP	193.7	103.6	CEII Redacted	P0	Increase conductor clearance for 55C operation (15 miles)
J1140	West St. Cloud-Westwood 115 kV	246.7	GRE XEL	272.9	110.6	CEII Redacted	P1	Rebuild 0.6 mi to 2x795 ACSS

Generator	Constraint	Rating	Owner	Worst Loading		Contingency	Cont Type	Mitigation
				(MVA)	(%)			
J1140	West St. Cloud-Westwood 115 kV	246.7	GRE XEL	275.3	111.6	CEII Redacted	P2-P7	Rebuild 0.6 mi to 2x795 ACSS
J1105	Chub Lake 345-115-34.5 kV xfmr	448.0	GRE	606.2	135.3	CEII Redacted	P2-P7	Add second 345/115 kV transformer at Chub Lake
J1140	STSTPHNT-Fishill 115 kV	124.5	GRE	131.2	105.4	CEII Redacted	P1	GRE: XEL owns equipment and line. $0 XEL: Uprate line to 795 ACSS. $5.1M

Generator	Constraint	Rating	Owner	Worst Loading		Contingency	Cont Type	Mitigation
				(MVA)	(%)			
J1140	STSTPHNT-Fishill 115 kV	124.5	GRE	131.9	105.9	CEII Redacted	P2-P7	GRE: XEL owns equipment and line. $0 XEL: Uprate line to 795 ACSS. $5.1M
J975	CSLTNET-Mapleton 115 kV	263.0	OTP	316.9	120.5	CEII Redacted	P1	CSLTNET-Mapleton 115 kV Uprate. LPC NU in DPP 2017 Aug West Ph2
J975	CSLTNET-Mapleton 115 kV	263.0	OTP	319.0	121.3	CEII Redacted	P2-P7	CSLTNET-Mapleton 115 kV Uprate. LPC NU in DPP 2017 Aug West Ph2
J975	Buffalo 345-230-41.6 kV xfmr #2	140.0	OTP	181.2	129.4	CEII Redacted	P2-P7	Replace Buffalo transformer #2 with larger unit.
J1040	Hankinson-Forman 230 kV	432.1	OTP	487.5	112.8	CEII Redacted	P1	Hankinson-Forman 230 kV Uprate. LPC NU in DPP 2017 Aug West Ph2
J1040	Wahpeton-Fergus Falls 230 kV	379.1	OTP MRES	404.3	106.7	CEII Redacted	P0	Wahpeton-Fergus Falls 230 kV Uprate. NU in DPP 2017 Aug West Ph2
J1040	Wahpeton-Fergus Falls 230 kV	379.1	OTP MRES	396.0	104.4	CEII Redacted	P1	Wahpeton-Fergus Falls 230 kV Uprate. NU in DPP 2017 Aug West Ph2

Generator	Constraint	Rating	Owner	Worst Loading		Contingency	Cont Type	Mitigation
				(MVA)	(%)			
J975	Audubon-Lake Park 230 kV	294.0	OTP	349.0	118.7	CEII Redacted	P0	Audubon-Lake Park 230 kV Uprate. NU in DPP 2017 Aug West Ph2
J975,J1040,J1187	Audubon-Lake Park 230 kV	294.0	OTP	355.4	120.9	CEII Redacted	P1	Audubon-Lake Park 230 kV Uprate. NU in DPP 2017 Aug West Ph2
J1040	Big Stone South 345-230-34.5 kV #1	525.8	OTP	573.6	109.1	CEII Redacted	P2-P7	Big Stone South Transformer #1 Upgrade. LPC NU in DPP 2017 Aug West Ph2
J1040	Big Stone South 345-230-34.5 kV #2	525.8	OTP	573.7	109.1	CEII Redacted	P2-P7	Big Stone South Transformer #2 Upgrade. LPC NU in DPP 2017 Aug West Ph2
J1128	Ellendale-County Line 69 kV	48.0	ITCM	57.2	119.2	CEII Redacted	P1	Rebuild 5.79 miles
J1128	Hayward-County Line 69 kV	48.0	ITCM	59.2	123.3	CEII Redacted	P1	Rebuild 13.32 miles
J1132	Osceola-Osceola REC 69 kV	38.0	ITCM CIPCO	41.1	108.2	CEII Redacted	P0	ITCM: ITCM rating 42/44 MVA SN/SE CIPCO: NU is not required unless identified in affected system study
J1128	Adams-Hayward 161 kV	233.0	ITCM	256.7	110.2	CEII Redacted	P1	Adams-Hayward 161 kV Uprate. NU in DPP 2017 Aug West Ph2

Generator	Constraint	Rating	Owner	Worst Loading		Contingency	Cont Type	Mitigation
				(MVA)	(%)			
J1110,J1128	Adams-Hayward 161 kV	233.0	ITCM	256.6	110.1	CEII Redacted	P2-P7	Adams-Hayward 161 kV Uprate. NU in DPP 2017 Aug West Ph2
J1181	Hazleton-Arnold 345 kV	923.0	ITCM MEC	953.9	103.4	CEII Redacted	P1	MEC: MEC owns a portion of line conductor. Structure replacements. New MEC Only rating expected to be 1139/1139 MVA. $800K ITCM: Structure replacements. New ITCM rating 1285 MVA/SN/SE. $480K
J959,J967,J1072,J1181	Hazleton-Arnold 345 kV	923.0	ITCM MEC	1105.9	119.8	CEII Redacted	P2-P7	MEC: MEC owns a portion of line conductor. Structure replacements. New MEC Only rating expected to be 1139/1139 MVA. $800K ITCM: Structure replacements. New ITCM rating 1285 MVA/SN/SE. $480K
J1181	Hazleton-Hickory Crk 345 kV	1195.0	ITCM	1223.3	102.4	CEII Redacted	P1	ITCM rating 1569 MVA SN/SE
J1024	Adams-Creston 161 kV	154.0	MEC WAPA	159.3	103.4	CEII Redacted	P1	Structure replacements. New rating expected to be 182/182 MVA

Generator	Constraint	Rating	Owner	Worst Loading		Contingency	Cont Type	Mitigation
				(MVA)	(%)			
J1024	Adams-Creston 161 kV	154.0	MEC WAPA	158.3	102.8	CEII Redacted	P2-P7	Structure replacements. New rating expected to be 182/182 MVA
J1174,J1175	Webster-Wright 161 kV	212.0	MEC	219.6	103.6	CEII Redacted	P1	Reconductor line and substation terminal equipment upgrades. New rating predicted to be 315/335 MVA.
J1174,J1175	Franklin-Wall Lake 161 kV	204.0	MEC	237.4	116.4	CEII Redacted	P1	Reconductor line. New rating predicted to be 335/335 MVA.
J952	Red Willow-Mingo 345 kV	785.0	NPPD SUNC	822.9	104.8	CEII Redacted	P1	NU is not required unless it is identified as constraint in affected system study.
J1040	Ward-Bismark 230 kV	352.0	BEPC WAPA	403.7	114.7	CEII Redacted	P1	NU is not required unless it is identified as constraint in affected system study.
J1040	Ward-Bismark 230 kV	352.0	BEPC WAPA	458.3	130.2	CEII Redacted	P2-P7	NU is not required unless it is identified as constraint in affected system study.
J975,J1040,J1187	Ft. Thompson 345 kV bus 1-3 tie	717.0	WAPA	749.4	104.5	CEII Redacted	P0	NU is not required unless it is identified as constraint in affected system study.
J975,J1040,J1140,J1187	Ft. Thompson 345 kV bus 1-3 tie	717.0	WAPA	778.2	108.5	CEII Redacted	P1	NU is not required unless it is identified as constraint in affected system study.

Generator	Constraint	Rating	Owner	Worst Loading		Contingency	Cont Type	Mitigation
				(MVA)	(%)			
J975	Wilton-Winger 230 kV	288.0	MPC OTP	301.8	104.8	CEII Redacted	P0	OTP: Sufficient for the flows of 395.2 MVA. $0
J975,J1040,J1187	Wilton-Winger 230 kV	288.0	MPC OTP	307.6	106.8	CEII Redacted	P1	OTP: Sufficient for the flows of 395.2 MVA. $0
J1040	Ellendale-Aberdeen 115 kV	128.0	MDU NWE	146.2	114.2	CEII Redacted	P1	Ellendale-Aberdeen Jct 115 kV Uprate. LPC NU in DPP 2017 Aug West Ph2
J1040	Heskett-J302 POI 230 kV	383.0	MDU	689.1	179.9	CEII Redacted	P1	Add a breaker at Merricourt and build 2nd Mandan-Napoleon SW 230 kV line w/ 1272 ACSS (includes river crossing).
J1040	Heskett-J302 POI 230 kV	383.0	MDU	864.6	225.7	CEII Redacted	P2-P7	Add a breaker at Merricourt and build 2nd Mandan-Napoleon SW 230 kV line w/ 1272 ACSS (includes river crossing).
J1040	Heskett-Mandan 230 kV	383.0	MDU	584.1	152.5	CEII Redacted	P1	The Heskett 230 kV sub has an estimated retirement date of 7/23/2021. When the Heskett 230 kV sub is retired, this constraint will no longer exist.
J1040	Heskett-Mandan 230 kV	383.0	MDU	742.6	193.9	CEII Redacted	P2-P7	The Heskett 230 kV sub has an estimated retirement date of 7/23/2021. When the Heskett 230 kV sub is retired, this constraint will no longer exist.

Generator	Constraint	Rating	Owner	Worst Loading		Contingency	Cont Type	Mitigation
				(MVA)	(%)			
J1040	Heskett 230-115-13.8 kV xfmr	239.0	MDU	261.4	109.4	CEII Redacted	P1	The Heskett 230/115 kV transformer is planned to be moved to Mandan to function in parallel to the existing Mandan 230/115 kV transformer. Once the Heskett 230/115 kV transformer is moved, this constraint will no longer exist.
J1040	Heskett 230-115-13.8 kV xfmr	239.0	MDU	258.1	108.0	CEII Redacted	P2-P7	The Heskett 230/115 kV transformer is planned to be moved to Mandan to function in parallel to the existing Mandan 230/115 kV transformer. Once the Heskett 230/115 kV transformer is moved, this constraint will no longer exist.
J1040	Mandan-Ward 230 kV	391.0	MDU BEPC	428.3	109.5	CEII Redacted	P1	MDU's rating at Mandan is 956 MVA. MPC owns equipment at Mandan. WAPA owns the line. BEPC owns Ward.
J1040	Mandan-Ward 230 kV	391.0	MDU BEPC	482.1	123.3	CEII Redacted	P2-P7	MDU's rating at Mandan is 956 MVA. MPC owns equipment at Mandan. WAPA owns the line. BEPC owns Ward.
J1040	Fox Tail-Tatanka North 230 kV	478.0	MDU	555.4	116.2	CEII Redacted	P1	Major substation upgrades at Tatanka North 230 (new rating: 610/610 MVA [N/E]).

Generator	Constraint	Rating	Owner	Worst Loading		Contingency	Cont Type	Mitigation
				(MVA)	(%)			
J1040	Fox Tail-Tatanka North 230 kV	478.0	MDU	556.5	116.4	CEII Redacted	P2-P7	Major substation upgrades at Tatanka North 230 (new rating: 610/610 MVA [N/E]).
J1040	Fox Tail-Ellendale 230 kV	610.0	MDU	643.5	105.5	CEII Redacted	P1	Foxtail-Ellendale 230 kV Rebuild. LPC NU in DPP 2017 Aug West Ph2
J1040	Fox Tail-Ellendale 230 kV	610.0	MDU	644.7	105.7	CEII Redacted	P2-P7	Foxtail-Ellendale 230 kV Rebuild. LPC NU in DPP 2017 Aug West Ph2
J952,J1040,J1187	Merricourt-Wishek 230 kV	343.0	MDU	367.0	107.0	CEII Redacted	P0	Rebuild/reconductor line with 1272 ACSS (new rating: 797/797 MVA [N/E]).
J952,J1040,J1187	Merricourt-Wishek 230 kV	343.0	MDU	686.7	200.2	CEII Redacted	P1	Rebuild/reconductor line with 1272 ACSS (new rating: 797/797 MVA [N/E]).
J1040	Merricourt-Wishek 230 kV	343.0	MDU	686.7	200.2	CEII Redacted	P2-P7	Rebuild/reconductor line with 1272 ACSS (new rating: 797/797 MVA [N/E]).
J1040	Merricourt-Tatanka North 230 kV	324.0	MDU	450.0	138.9	CEII Redacted	P1	Rebuild line to ACSS. New Rating: 478/478 MVA.

Generator	Constraint	Rating	Owner	Worst Loading		Contingency	Cont Type	Mitigation
				(MVA)	(%)			
J1040	Merricourt-Tatanka North 230 kV	324.0	MDU	451.1	139.2	CEII Redacted	P2-P7	Rebuild line to ACSS. New Rating: 478/478 MVA.
J1040	Merricourt-Ellendale 230 kV	610.0	MDU	630.9	103.4	CEII Redacted	P1	Rebuild/reconductor Merricourt-Ellendale345 230 kV line w/ 1272 ACSS (new rating: 776/776 MVA [N/E]).
J1040	Merricourt-Ellendale 230 kV	610.0	MDU	613.6	100.6	CEII Redacted	P2-P7	Rebuild/reconductor Merricourt-Ellendale345 230 kV line w/ 1272 ACSS (new rating: 776/776 MVA [N/E]).
J1040	Wishek-J302 POI 230 kV	343.0	MDU	386.7	112.7	CEII Redacted	P2-P7	J302 POI-Wishek 230 kV Rebuild. NU in DPP 2017 Aug West Ph2
J967,J1072,J1110,J1124, J1128,J1181	Wabaco-Rochester 161 kV	221.1	DPC	317.8	143.7	CEII Redacted	P1	Rebuild line with 795 ACSS conductor. $11M. MTEP Appendix A project
J967,J1181	Wabaco-Rochester 161 kV	221.1	DPC	326.0	147.4	CEII Redacted	P2-P7	Rebuild line with 795 ACSS conductor. $11M. MTEP Appendix A project

Generator	Constraint	Rating	Owner	Worst Loading		Contingency	Cont Type	Mitigation
				(MVA)	(%)			
J1181	Wabaco-Alma 161 kV	291.0	DPC	301.4	103.6	CEII Redacted	P1	Rebuild line with 795 ACSS conductor
J967,J1181	Wabaco-Alma 161 kV	291.0	DPC	311.2	106.9	CEII Redacted	P2-P7	Rebuild line with 795 ACSS conductor

4.5 Network Upgrades Identified in MISO ERIS Analysis for 2024 Summer Shoulder Scenario

Based on the MISO 2024 summer shoulder steady state analyses, the MISO Base Case NU and two DPP 2017 August Phase 2 NUs required for mitigating potential voltage collapse and severe thermal overloads are listed in Table 4-3. Additional thermal NUs and cost are listed in Table 4-4, and additional reactive power NUs and cost are listed in Table 4-5.

Table 4-3: Network Upgrades Required for Mitigating Voltage Collapse and Severe Thermal Overloads

NUs	Needs	Miles	Cost ($)
Hazel Creek-Scott County 345 kV	Base Case NU	115	$210,829,263
Big Stone South-Twin Brooks 345 kV 2nd Circuit	DPP 2017 Aug. Ph2 NU	30.25	$54,500,000[1]
New J628 POI– Prairie 230 kV 2nd Circuit	DPP 2017 Aug. Ph2 NU	11	$22,360,000[1]

Note 1: The cost is currently assigned to projects in DPP 2017 Aug. Phase 2 cycle. The NU cost may be assigned to DPP 2018 Apr. projects if projects in DPP 2017 Aug. are withdrawn.

Table 4-4: Additional Thermal NUs

Constraint	Owner	Mitigation	Cost ($)
J1024 POI-Clarinda 161 kV	MEC	MEC: substation terminal equipment upgrades. New rating predicted to be 410 MVA.	$700,000
J1181 POI-Hazleton 345 kV	MEC ITCM	MEC: MEC owns portion of line conductor. Structure replacements. New MEC Only rating expected to be 1094/1094 MVA. $600,000 ITCM: ITCM records show a rating of 1006 MVA summer. $0	$600,000
J611 POI-Maryville 161 kV	MEC GMO	MEC: Existing MEC only rating expected to be 410 MVA after DPP 2016 AUG West line reconductor network upgrade. GMO: NU is not required unless it is identified as constraint in affected system study.	$0
J720 POI-Lakefield 345 kV	ITCM	ITCM records show a rating of 932 MVA summer limit due to MEC facilities.	$0
G16-017 Tap-Ft. Thompson 345 kV	WAPA	NU is not required unless it is identified as constraint in affected system study.	$0
Wilmarth-Field North 345 kV	XEL	Fieldon-Wilmarth 345 rebuild	$96,300,000
Wilmarth-Sheas Lake 345 kV	XEL	Wilmarth-Sheas Lake 345 kV Rebuild. NU in DPP 2017 Aug West Ph2	$0[1]
Split Rock-White 345 kV	XEL WAPA	XEL: Limiter is on WAPA facility. $0 WAPA: NU is not required unless it is identified as constraint in affected system study.	$0
Blue Lake-Scott Co 345 kV	XEL	Blue Lake-Scott County 345 kV Rebuild. NU in DPP 2017 Aug West Ph2	$0[1]

Constraint	Owner	Mitigation	Cost ($)
Field South-Field North 345 kV	XEL	bypassing the Fieldon series cap	$500,000
Field South-Crandal 345 kV	XEL	Crandal-Fieldon 345 kV Rebuild. NU in DPP 2017 Aug West Ph2	$0[1]
Lyon Co-Hazel Creek 345 kV	XEL	Upgrade some sub equipment at Hazel that would put the rating to 1790 MVA normal and emergency	$200,000
Helena-Sheas Lk 345 kV	XEL	Helena-Sheas Lake 345 kV Rebuild. NU in DPP 2017 Aug West Ph2	$0[1]
Sheyenne-Lake Park 230 kV	XEL MPC OTP	Sheyenne-Lake Park 230 kV Uprate. NU in DPP 2017 Aug West Ph2	$0[1]
Sheyenne-Mapleton 115 kV	XEL OTP	Sheyenne-Mapleton 115 kV Rebuild. NU in DPP 2017 Aug West Ph2	$0[1]
M.E. International-Westwood 115 kV	XEL GRE	XEL: Rebuild ME International to Westwood tap (2.1 miles) with 795 ACSS conductor and replace line switches. $5,000,000 GRE: XEL facility	$5,000,000
Austin-Murphy 161 kV	SMMPA	Austin-Murphy Creek 161 kV Rebuild. NU in DPP 2017 Aug West Ph2	$0[1]
Murphy-J1128 POI 161 kV	SMMPA	Murphy Creek – Hayward 161 kV Rebuild. NU in DPP 2017 Aug West Ph2	$0[1]
Hubbard-Badoura 230 kV	MP	Increase conductor clearance for 55C operation (15 miles)	$1,350,000
West St. Cloud-Westwood 115 kV	GRE XEL	Rebuild 0.6 mi to 2x795 ACSS	$900,000
Chub Lake 345-115-34.5 kV xfmr	GRE	Add second 345/115 kV transformer at Chub Lake	$11,400,000
STSTPHNT-Fishill 115 kV	GRE	GRE: XEL owns equipment and line. $0 XEL: Uprate line to 795 ACSS. $5.1M	$5,100,000
CSLTNET-Mapleton 115 kV	OTP	CSLTNET-Mapleton 115 kV Uprate. LPC NU in DPP 2017 Aug West Ph2	$0[1]
Buffalo 345-230-41.6 kV xfmr #2	OTP	Replace Buffalo transformer #2 with larger unit.	$3,000,000
Hankinson-Forman 230 kV	OTP	Hankinson-Forman 230 kV Uprate. LPC NU in DPP 2017 Aug West Ph2	$0[1]
Wahpeton-Fergus Falls 230 kV	OTP MRES	Wahpeton-Fergus Falls 230 kV Uprate. NU in DPP 2017 Aug West Ph2	$0[1]
Audubon-Lake Park 230 kV	OTP	Audubon-Lake Park 230 kV Uprate. NU in DPP 2017 Aug West Ph2	$0[1]
Big Stone South 345-230-34.5 kV #1	OTP	Big Stone South Transformer #1 Upgrade. LPC NU in DPP 2017 Aug West Ph2	$0[1]
Big Stone South 345-230-34.5 kV #2	OTP	Big Stone South Transformer #2 Upgrade. LPC NU in DPP 2017 Aug West Ph2	$0[1]

Constraint	Owner	Mitigation	Cost ($)
Ellendale-County Line 69 kV	ITCM	Rebuild 5.79 miles	$4,200,000
Hayward-County Line 69 kV	ITCM	Rebuild 13.32 miles	$9,700,000
Osceola-Osceola REC 69 kV	ITCM CIPCO	ITCM: ITCM rating 42/44 MVA SN/SE CIPCO: NU is not required unless identified in affected system study	$0
Adams-Hayward 161 kV	ITCM	Adams-Hayward 161 kV Uprate. NU in DPP 2017 Aug West Ph2	$0[1]
Hazleton-Arnold 345 kV	ITCM MEC	MEC: MEC owns a portion of line conductor. Structure replacements. New MEC Only rating expected to be 1139/1139 MVA. $800K ITCM: Structure replacements. New ITCM rating 1285 MVA/SN/SE. $480K	$1,280,000
Hazleton-Hickory Crk 345 kV	ITCM	ITCM rating 1569 MVA SN/SE	$0
Adams-Creston 161 kV	MEC WAPA	Structure replacements. New rating expected to be 182/182 MVA	$800,000
Webster-Wright 161 kV	MEC	Reconductor line and substation terminal equipment upgrades. New rating predicted to be 315/335 MVA.	$8,000,000
Franklin-Wall Lake 161 kV	MEC	Reconductor line. New rating predicted to be 335/335 MVA.	$12,000,000
Red Willow-Mingo 345 kV	NPPD SUNC	NU is not required unless it is identified as constraint in affected system study.	$0
Ward-Bismark 230 kV	BEPC WAPA	NU is not required unless it is identified as constraint in affected system study.	$0
Ft. Thompson 345 kV bus 1-3 tie	WAPA	NU is not required unless it is identified as constraint in affected system study.	$0
Wilton-Winger 230 kV	MPC OTP	OTP: Sufficient for the flows of 395.2 MVA. $0	$0
Ellendale-Aberdeen 115 kV	MDU NWE	Ellendale-Aberdeen Jct 115 kV Uprate. LPC NU in DPP 2017 Aug West Ph2	$0[1]
Heskett-J302 POI 230 kV	MDU	Add a breaker at Merricourt and build 2nd Mandan-Napoleon SW 230 kV line w/ 1272 ACSS (includes river crossing).	$81,500,000
Heskett-Mandan 230 kV	MDU	The Heskett 230 kV sub has an estimated retirement date of 7/23/2021. When the Heskett 230 kV sub is retired, this constraint will no longer exist.	$0
Heskett 230-115-13.8 kV xfmr	MDU	The Heskett 230/115 kV transformer is planned to be moved to Mandan to function in parallel to the existing Mandan 230/115 kV transformer. Once the Heskett 230/115 kV transformer is moved, this constraint will no longer exist.	$0

Constraint	Owner	Mitigation	Cost ($)
Mandan-Ward 230 kV	MDU BEPC	MDU's rating at Mandan is 956 MVA. MPC owns equipment at Mandan. WAPA owns the line. BEPC owns Ward.	$0
Fox Tail-Tatanka North 230 kV	MDU	Major substation upgrades at Tatanka North 230 (new rating: 610/610 MVA [N/E]).	$1,500,000
Fox Tail-Ellendale 230 kV	MDU	Foxtail-Ellendale 230 kV Rebuild. LPC NU in DPP 2017 Aug West Ph2	$0[1]
Merricourt-Wishek 230 kV	MDU	Rebuild/reconductor line with 1272 ACSS (new rating: 797/797 MVA [N/E]).	$15,000,000
Merricourt-Tatanka North 230 kV	MDU	Rebuild line to ACSS. New Rating: 478/478 MVA.	$1,000,000
Merricourt-Ellendale 230 kV	MDU	Rebuild/reconductor Merricourt-Ellendale345 230 kV line w/ 1272 ACSS (new rating: 776/776 MVA [N/E]).	$15,000,000
Wishek-J302 POI 230 kV	MDU	J302 POI-Wishek 230 kV Rebuild. LPC NU in DPP 2017 Aug West Ph2	$0[1]
Wabaco-Rochester 161 kV	DPC	Rebuild line with 795 ACSS conductor. $11M. MTEP Appendix A project	$0[2]
Wabaco-Alma 161 kV	DPC	Rebuild line with 795 ACSS conductor	$6,300,000

Note 1: Costs of Network Upgrades required in DPP 2017 Aug West Ph2 are currently assigned to projects in DPP 2017 Aug. Phase 2 cycle. The NUs cost may be assigned to DPP 2018 Apr. projects if projects in DPP 2017 Aug. are withdrawn.

Note 2: This is approximate $11,000,000 Appendix A project in MTEP that is being disputed.

Table 4-5: Additional Reactive Power NUs

Network Upgrades	Owner	Cost ($)
Add 1×40 Mvar switched capacitor at Oakes 230 kV (620362)	OTP	$2,000,000

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Section
5

Local Planning Criteria Analysis

Local Planning Criteria (LPC) analyses were performed to identify additional constraints per Transmission Owning Companies' LPC.

5.1 GRE Local Planning Criteria Analysis

Great River Energy (GRE) determined with provided rationale that the GRE LPC should be applied to the projects listed in Table 5-1. The GRE LPC analysis consisted of steady-state contingency analysis and stability analysis for summer shoulder condition.

Table 5-1: DPP Projects with GRE LPC Applicable

MISO Project	Pmax (MW)	Fuel type	POI	Rationale
J1106	414	Wind	Lyon County - Cedar Mountain 345 kV	GRE is the maintainer for this CapX-owned facility and responsible for the compliance with the NERC standards (FAC-002, TPL-001) associated with new interconnections
J1140	80	Solar	Langola Tap 115 kV	GRE is the Transmission owner of the transmission line
J1187	151.8	Wind	Stanton 230 kV	GRE is the owner of the substation

Based on geographic locations of the projects' Point of Interconnection (POI), the projects were separated into the following three groups for GRE LPC study:

- J1106 GRE LPC group: J1106
- J1140 GRE LPC group: J1140
- CCS GRE LPC group: J1187

Siemens PTI performed the GRE local planning criteria analysis based on GRE's LPC. The J1106 GRE local planning criteria analysis details can be found in Appendix F.1.1, the J1140 GRE local planning criteria analysis details can be found in Appendix F.1.2, and the CCS (J1187) GRE local planning criteria analysis details can be found in Appendix F.1.3.

5.1.1 Additional Network Upgrades Identified in J1106 GRE LPC Analysis

Additional Network Upgrades required in the J1106 GRE LPC study are listed in Table 5-2.

Table 5-2: Additional Network Upgrades Required in the J1106 GRE LPC Study

Constraint	Owner	Mitigation	Cost ($)
Helena-Chub Lake 345 kV	GRE CAPX	Helena-Chub Lake 2nd Circuit, $34M. NU in DPP 2017 Aug West Ph2	$0 [1]

Note 1: Costs of Network Upgrades required in DPP 2017 Aug West Ph2 are currently assigned to projects in DPP 2017 Aug. Phase 2 cycle. The NUs cost may be assigned to DPP 2018 Apr. projects if projects in DPP 2017 Aug. are withdrawn.

5.1.2 Additional Network Upgrades Identified in J1140 GRE LPC Analysis

No additional Network Upgrades are required in the J1140 GRE LPC study.

5.1.3 Additional Network Upgrades Identified in CCS (J1187) GRE LPC Analysis

Transient instability and voltage collapse were identified under three CUDC related contingencies (Table 5-3) in the benchmark case stability analysis. To mitigate transient instability and voltage collapse identified in the CCS (J1187) GRE LPC benchmark case, it is proposed to build 2nd CUDC HVDC bipole. Study projects in the DPP 2018 April cycle are not responsible for this Network Upgrade required in the benchmark case.

Table 5-3: Voltage Collapse in the Benchmark Case under Permanent CUDC Bipole Faults

CEII Redacted

With the 2nd CUDC HVDC bipole modeled in the CCS GRE LPC study case, no transient instability, or voltage collapse, or other stability violations were identified in the CCS GRE LPC study case.

Additional Network Upgrades required in the CCS GRE LPC study are listed in Table 5-4.

Table 5-4: Additional Network Upgrades for Constraints Identified in CCS GRE LPC Analysis

Constraint	Owner	Network Upgrades	Cost ($)
Voltage collapse in Benchmark Case under CUDC contingencies	GRE	Build 2nd CUDC HVDC bipole	Not Available [1]
Hubbard-Erie Jct 230 kV	GRE OTP MP	GRE: GRE equipment at Hubbard is rated 522.6 MVA. $0 OTP: Sufficient for flows seen in study. $0 MP: Reconductor on MP’s segment. $2.265M	$0
West St. Cloud-Lesauk Tap 115 kV	GRE XEL	GRE: XEL owns the circuit and equipment. $0 XEL: Uprate line to 795 ACSS. $2.1M	$0
Stanton-Leland Olds 230 kV	GRE BEPC	GRE: Replace 4 switches, $2.5M BEPC: Update the line reactor. $900K	$2,500,000

Constraint	Owner	Network Upgrades	Cost ($)
Lesauk Tap-Fishill 115 kV	GRE XEL	GRE: XEL owns equipment and line. $0 XEL: NU is not required for GRE LPC. Uprate line to 795 ACSS. $4.5M	$0

Note 1: Study projects in the DPP 2018 Apr. cycle are not responsible for these Network Upgrades required in the benchmark case.

5.2 OTP Local Planning Criteria Analysis

J975 is to be interconnected in Otter Tail Power (OTP) transmission system. In addition to MISO's standard DPP analysis, OTP determined that J975 is required for OTP LPC study. The OTP LPC analysis consisted of steady-state contingency analysis for summer shoulder, summer peak, and Light Load No Wind conditions.

Three additional scenarios were analyzed in the OTP LPC study:

1. OTP LPC Summer Peak (SPK)
2. OTP LPC Summer Shoulder (SH)
3. OTP LPC Light Load No Wind (LLNW)

Siemens PTI performed the local planning criteria analysis based on OTP's LPC. The OTP local planning criteria analysis details can be found in Appendix F.2.

5.2.1 Additional Network Upgrades Identified in OTP LPC Analysis

No voltage constraints were identified in the OTP LPC analysis.

With future Erie substation, the rating of the Erie Jct. - Audubon 230 kV will be 360.9 MVA normal and emergency. Therefore, no additional Network Upgrades are required in the OTP LPC study (Table 5-5).

Table 5-5: Additional Network Upgrades for Constraints Identified in OTP LPC Analysis

Constraint	Owner	Mitigation	Cost ($)
Erie Jct-Audubon 230 kV	OTP XEL	With future Erie substation, the rating of this line section will be 360.9 MVA normal & emergency. $0	$0

5.3 MDU Local Planning Criteria Analysis

Montana-Dakota Utilities Company (MDU) determined that J1040 has more than 20% DF on the outlets of Tatanka, Foxtail, J436/J437/J488, J302/J503, G359 (Merricourt), J580, and J933. In addition to MISO's standard DPP analysis, MDU determined that J1040 is required for MDU LPC study per Section 3.2 of the MDU Local Planning Criteria. The MDU LPC analysis consisted of steady-state contingency analysis and stability analysis for summer shoulder condition.

One additional scenario was analyzed in the MDU LPC study:

a. MDU LPC Summer Shoulder (SH)

Siemens PTI performed the local planning criteria analysis based on MDU's LPC. The MDU local planning criteria analysis details can be found in Appendix F.3.

5.3.1 Additional Network Upgrades Identified in MDU LPC Analysis

Additional Network Upgrades required in the MDU LPC study are listed in Table 5-6.

Table 5-6: Additional Network Upgrades for Constraints Identified in MDU LPC Analysis

Constraint	Owner	Mitigation	Cost ($)
East Bismark-Bismark 115 kV	MDU WAPA	MDU equipment can be rated up to 199/249 MVA [N/E]. WAPA terminal is limiting.	$0
Mandan-J302 POI 230 kV #1	MDU	Rebuild Mandan-J302 POI 230 kV line (Ckt '1') with 1272 ACSS conductor (includes river crossing). New rating: 797/824 MVA [N/E]).	$48,400,000
Mandan-Ward 230 kV	MDU BEPC WAPA MPC	MDU's rating at Mandan is 956 MVA. MPC owns equipment at Mandan. WAPA owns the line. BEPC owns Ward.	$0

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Section

6

Affected System Steady-State Analysis

Steady state analyses were performed to identify constraints in affected systems.

6.1 Affected System Analysis for CIPCO Company

Per CIPCO Affected System Planning Criteria, a CIPCO transmission facility is a constraint if it satisfies all three of the following conditions:

1. the branch is loaded above its applicable normal or emergency rating for the post-change case, and
2. the generator has a larger than 3% DF on the overloaded facility under post contingent condition or 5% DF under system intact condition, and
3. the loading increase of the overloaded facility is greater than 1 MVA compared with that in the pre-change case under system intact or contingency conditions.

AC contingency analysis was performed for this CIPCO affected system analysis, using the following benchmark and study cases:

- Summer peak benchmark and study cases
- Summer shoulder benchmark and study cases

All NERC category P0-P7 contingencies described in Section 2.2 were simulated. The CIPCO affected system was monitored.

CIPCO thermal constraints identified in the affected system analysis are listed in Appendix G.1. The highest loading and potential network upgrades for summer shoulder system conditions are listed in Table 6-1. There are no CIPCO thermal constraints for summer peak conditions.

Table 6-1. CIPCO Summer Shoulder Thermal Constraints, Maximum Screened Loading, Stage-2 ACCC

Generator	Constraint	Rating	Owner	Worst Loading (MVA)	Worst Loading (%)	Contingency	Cont Type	Mitigation	Cost ($)
J1132	Murray-I35 Tap 69 kV	69.0	CIPCO	69.1	100.2	CEII Redacted	P1	Rebuild 5.68 miles with T2-4/0 ACSR at $350k per mile.	$1,988,000
J1132	Murray-I35 Tap 69 kV	69.0	CIPCO	69.1	100.2	CEII Redacted	P2-P7	Rebuild 5.68 miles with T2-4/0 ACSR at $350k per mile.	
J1132	Osceola-Osceola REC 69 kV	38.0	CIPCO ITCM	55.3	145.6	CEII Redacted	P1	Not a CIPCO constraint	$0
J1132	Osceola-Osceola REC 69 kV	38.0	CIPCO ITCM	55.3	145.6	CEII Redacted	P2-P7	Not a CIPCO constraint	
J959,J1174,J1175, J1181	Liberty-Hickory Crk 161 kV	327.0	CIPCO ITCM	343.6	105.1	CEII Redacted	P2-P7	Replace switches and jumpers	$100,000

6.2 MPC Affected System Analysis

The MPC affected system analysis details can be found in Appendix G.2.

6.2.1 Study Summary

Minnkota Power Cooperative (MPC) performed an Affected System Analysis (ASA) to determine impacts of generators in the MISO DPP 2018 April Phase 2 study cycle on MPC facilities and any network upgrades required to mitigate those impacts. Steady-state power flow analysis, steady-state contingency analysis, and dynamic stability analysis were performed for three DPP generating facility.

- J975, ERIS, 150 MW wind at Buffalo 115 kV substation
- J1040, NRIS, 250 MW wind at Wishek Jct 230 kV substation
- J1187, NRIS, 151.8 MW wind at Stanton 230 kV substation

6.2.2 Network Upgrades

The Network Upgrades required to mitigate constraints identified in the Minnkota ASA are listed in Table 6-2 through Table 6-5. Costs are planning level estimates and subject to revision in the facility studies.

Table 6-2. Minnkota Network Upgrades Allocated to DPP 2018 Projects

Constraint	Highest Loading (MVA)	Owner	Mitigation	Cost ($)	Generators
Drayton 230-115 kV xfmr 1	172	OTP MPC	Replace Transformer	$2,100,000	J1187,
Prairie-Walle 230	462	MPC	Rebuild line to achieve a minimum of 462 MVA	$6,000,000	J1040, J1187,
			Total	**$8,100,000**	

Table 6-3: Minnkota Network Upgrades Allocated to DPP 2017 Aug Projects

Constraint	Highest Loading (MVA)	Owner	Mitigation
Bemidji-Helga 115	161	OTP	Replace Jumpers at Helga to achieve 162 MVA
Jamestown-Center 345	705	MPC OTP	Resag conductor to 65 C to achieve 739 MVA
Grand Forks-Falconer 115	263	MPC	Replace conductor, CBs, switches, CT to achieve 291
Wilton-Winger 230	410	OTP MPC	Resag conductor to 100 C to achieve 444 MVA
Winger-Walle 230	433	MPC	Resag conductor to 100 C to achieve 437 MVA
Center 345-230 kV xfmr 1	853	MPC	Add 3rd Center transformer
Center 345-230 kV xfmr 2	852	MPC	

Table 6-4: DPP 2017 Aug ERIS Network Upgrades Allocated to DPP 2017 Aug Projects

Constraint	Mitigation	Owner
Voltage collapse	Install 1x150 Mvar switched capacitor at Bison 345	XEL
Voltage collapse	Install 3x50 Mvar switched capacitor at Maple River 230	MPC
Voltage collapse	Install 3x50 Mvar switched capacitor at Wahpeton 230	OTP

Table 6-5: DPP 2017 Aug CCS GRE LPC Network Upgrades Allocated to DPP 2017 Aug Projects

Constraint	Mitigation	Owner
Transient instability	2×75 Mvar switched cap bank at Jamestown 345 kV	OTP
Transient instability	150 Mvar SVC at Jamestown 345 kV	OTP
Transient instability	2×75 Mvar switched cap bank at Alexandria 345 kV	MRES
Transient instability	200 Mvar SVC at Alexandria 345 kV	MRES
Transient instability	200 Mvar SVC at Wahpeton 230 kV	OTP
Transient instability	100 Mvar SVC at Prairie 345 kV	MPC
Transient instability	Alexandria - Twin Brooks 345 kV line	OTP/MRES
Transient instability	150 MVAR SVC at Ellendale 345 kV	OTP
Transient instability	200 MVAR SVC at Big Stone South 345 kV	OTP

6.3 PJM Affected System Analysis

The PJM affected system analysis details (dated 12/11/2020) can be found in Appendix G.3.

6.3.1 Study Results

6.3.1.1 Overload on Nelson;B- Electric JCT;R 345 kV line

The upgrade will be to re-conductor the line, station conductor work and upgrade 2-disconnnect switches. A preliminary estimate for the upgrade is $36.2 M.

These queue projects contribute to the constraint: J1084, J1131, J963, J952, J981, J959, J1181, J1135, J1000, J1050, J1174, J1175, J967, J1072, J1128, J1110, and J982.

The cost allocation is as follows:

Queue	MW Contribution	Percentage of Cost	Cost ($36.2M)
AE1-114	20.9	17.80%	$6.44
J981	24.8	21.12%	$7.65
J982	20.8	17.72%	$6.41
J1084	31.7	27.00%	$9.77
J1181	19.2	16.35%	$5.92

6.3.1.2 Overload on Pleasant Prairie – Zion EC 345 kV line

The ComEd end ALDR rating is 2792 MVA and is sufficient.

The MISO-end SE rating is 1526 MVA. This overload is driven by the 2018 DPP projects. A MISO/WEC upgrade is required to raise the MISO end SE rating to at least 1815 MVA.

6.3.1.3 Overload on East Frankford – Crete EC;B 345 kV line

The upgrade will be to reconductor the line at a preliminary estimate of $10.3M.

The 2018 April MISO DPP projects that contribute loading to this constraint are: J1101, J974, J959.

Based on PJM cost allocation criteria, DPP West project J959 is not responsible for cost towards the upgrade.

6.3.2 Study Summary

Multiple projects in the MISO DPP 2018 April West Area group contribute loading to the overloads in the PJM system. Some of these projects are responsible for the cost of Network Upgrades per PJM cost allocation rules.

6.4 AECI Affected System Analysis

The AECI affected system analysis details (dated 11/23/2020) can be found in Appendix G.4.

6.4.1 Study Results

Associated Electric Cooperative Inc. (AECI), through coordination with the Midcontinent Independent System Operator (MISO), has updated the analysis for generator interconnection requests (GIRs) within the DPP-2018-APR Study Cycle (the "Study Cycle") for an Affected System Study (AFS) evaluation on the AECI transmission system.

Steady state analysis was performed to confirm the reliability impacts on the AECI system under a variety of system conditions and outages. AECI's transmission system must be capable of operating within the applicable normal ratings, emergency ratings, and voltage limits of AECI planning criteria.

Steady state analysis results showed seven (7) new thermal violations reported due to the addition of the Study Cycle projects. Six (6) of these new violations are AECI owned facilities.

AECI developed non-binding, good faith estimates of the timing and cost estimates for upgrades needed as a result of the addition of the Study Cycle projects, as shown in Table 6-6. The associated cost allocation of the network upgrades to each of the Study Cycle projects is provided in Table 6-7.

Generation projects in DPP 2018 April West Phase 2 study cycle are not responsible for the cost of Network Upgrades identified in the AECI Affected System Study.

Table 6-6: Network Upgrade Costs

ID	Option / Description	Cost*	Year In Service
NU-01	Reconductor the 0.59-mile-long Essex to Stoddard 161 kV line to 954 ASCR	$861,000	TBD
NU-02	Reconductor the 2.44-mile-long Green Forest to Township 69 kV line to 336 ACSR	$2,895,000	TBD
	*2020$, includes engineering and contingencies Total Cost:	$1,756,000	

Table 6-7: Network Upgrade Cost Allocation

Project	NU-01	NU-02	Total Cost
J1007	$0	$59,000	$59,000
J1033	$157,000	$279,000	$436,000
J1034	$704,000	$1,255,000	$1,959,000
J1060	$0	$145,000	$145,000
J1087	$0	$656,000	$656,000
J1107	$0	$447,000	$447,000
J1125	$0	$54,000	$54,000
Total Cost	$861,000	$2,895,000	$3,756,000

6.5 SPP Affected System AC Contingency Analysis

Southwest Power Pool (SPP) conducted an Affected System Impact Study (ASIS) to evaluate potential impacts to the SPP Transmission System related to the interconnection of generators on the Mid-Continent Independent System Operation (MISO) Transmission System.

A steady-state thermal and voltage analysis as well as Transfer Distribution Factor analysis was performed to determine the impact the MISO GIRs have on the SPP system.

ERIS constraints identified in the SPP affected system are listed in Table 6-8.

NRIS constraints identified in the SPP affected system are listed in Table 6-9.

Cost allocation of SPP Network Upgrades are listed in Table 6-10.

The SPP affected system analysis results (02/16/2021) for this study are in Appendix G.5.

Table 6-8: SPP ERIS Constraints

Monitored Facility	Mitigation
Adams to Creston 161 kV Circuit	Reconductor Adams to Creston 161 kV Circuit
Oahe to Sully Buttes 230 kV Circuit	Oahe to Sully Buttes 230 kV Structure Replacement & Terminal Equipment Upgrade
Whitlock to Glenham 230 kV Circuit	Whitlock to Glenham 230 kV Structure Replacement & Terminal Equipment Upgrade
Bison to Hettinger 230 kV Circuit	Upgrade Terminal Equipment Bison to Hettinger 230 kV Circuit

Table 6-9: SPP NRIS Constraints

Monitored Facility	Mitigation
Cayler to Wisdom 161 kV Circuit	Cayler to Wisdom 161 kV Structure Replacement
Sheffield to Hampton Tap 161 kV Circuit	Rebuild Sheffield to Hampton Tap 161 kV Circuit
Yankton Jct. to NAPA Jct. 115 kV Circuit	Rebuild Yankton Jct. to NAPA Jct. 115 kV Circuit
Roland to ROLANDTP8 69 kV Circuit	Upgrade Terminal Equipment Roland to ROLDANDTP8 69 kV Circuit
ROLDANDTP8 to RADCLIFF8 69 kV Circuit	Upgrade Terminal Equipment ROLDANDTP8 to RADCLIFF8 69 kV Circuit
S3451 to S3454 345 kV Circuit	Upgrade Terminal Equipment S3451 to S3454 345 kV Circuit
S3451 to S3459 345 kV Circuit	Upgrade Terminal Equipment S3451 to S3459 345 kV Circuit
Emery to Sheffield 161 kV Circuit	Rebuild Emery to Sheffield 161 kV Circuit
Franklin to Hampton Tap 161 kV Circuit	Upgrade Terminal Equipment Franklin to Hampton Tap 161 kV Circuit

Table 6-10: SPP Network Upgrades Cost Allocation

Interconnection Request	Size	ERIS	NRIS	Total	ERIS Total	NRIS Total	Total
J1001	40	$0	$34,839	$34,839	$21,700,000	$35,830,142	$57,530,142
J1024	200	$12,000,000	$0	$12,000,000			
J1025	300	$0	$0	$0			
J1026	400	$0	$0	$0			
J1033	50	$0	$0	$0			
J1034	225	$0	$0	$0			
J1039	50	$0	$0	$0			
J1040	250	$465,966	$176,076	$642,042			
J1045	20	$0	$18,588	$18,588			
J1050	225	$0	$2,000,000	$2,000,000			
J1072	150	$0	$74,983	$74,983			
J1087	200	$0	$0	$0			
J1092	100	$0	$57,759	$57,759			
J1098	40	$0	$252,503	$252,503			
J1105	200	$0	$126,630	$126,630			
J1106	414	$0	$323,611	$323,611			
J1107	200	$0	$0	$0			
J1110	100	$0	$4,419,388	$4,419,388			
J1122	200	$0	$0	$0			
J1124	100	$0	$54,356	$54,356			
J1128	150	$0	$7,882,204	$7,882,204			
J1132	50	$0	$0	$0			
J1140	80	$0	$52,363	$52,363			
J1145	250	$0	$0	$0			
J1164	80	$0	$759,941	$759,941			
J1169	50	$0	$1,968,089	$1,968,089			
J1174	165	$0	$8,526,060	$8,526,060			
J1175	165	$0	$8,526,060	$8,526,060			
J1181	200	$0	$80,191	$80,191			
J1182	250	$0	$0	$0			
J1187	151.8	$318,142	$102,960	$421,102			

Interconnection Request	Size	ERIS	NRIS	Total	ERIS Total	NRIS Total	Total
J952	54	$8,700,000	$0	$8,700,000			
J953	2	$0	$0	$0			
J954	1.4	$0	$0	$0			
J956	200	$0	$0	$0			
J959	150	$0	$50,359	$50,359			
J967	150	$0	$74,983	$74,983			
J975	150	$215,892	$0	$215,892			
J976	300	$0	$0	$0			
J982	300	$0	$268,197	$268,197			
J987	100	$0	$0	$0			
J994	100	$0	$0	$0			

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Section

7

Stability Analysis

Stability analysis was performed to evaluate the transient stability and impact on the region of the generating facilities in the DPP 2018 April West study cycle.

7.1 Procedure

7.1.1 Computer Programs

Stability analysis was performed using TSAT revision 19.0.

7.1.2 Study Methodology

A stability package representing 2024 summer peak (PK) and summer shoulder (SH) conditions with generating facilities in the DPP 2018 April cycle was created from the MTEP19 stability package. Disturbances were simulated to evaluate the transient stability and impact on the region of the generating facilities. MISO transient stability criteria and local TOs' planning criteria specified in MTEP19 were adopted for checking stability violations.

7.2 Case Development

7.2.1 Summer Peak (PK) Stability Model

Summer peak stability model is the same as the summer peak steady state model. The model does not have the fictitious SVCs in SPP (Table 2-1), nor does it have the identified steady state ERIS Network Upgrades (Table 4-3, Table 4-4, Table 4-5).

7.2.2 Summer Shoulder (SH) Stability Model

Summer shoulder stability model was created from the summer shoulder steady state model (Section 2.1). The summer shoulder stability model includes the following Network Upgrades:

- DPP 2018 April Phase 2 steady state ERIS Network Upgrades (Table 4-3, Table 4-4, Table 4-5).
- Due to low voltages (around 0.93 p.u.) under system intact condition in areas of Bison (601067), Alexandria (658049), Maple River (620361) 345 kV, switched capacitors (Table 7-1) which are ERIS NUs in DPP 2017 August Phase 2 were added.

Table 7-1: Modeled Switched Capacitors Required in DPP 2017 August Phase 2

Bus Name	Bus Number	Size
Bison	601067	1 x 150 MVAR
Maple River	620361	3 x 50 MVAR

7.3 Disturbance Criteria

The stability simulations performed as part of this study considered all the regional and local contingencies listed in Table 7-2. Regional contingencies with pre-defined switching sequences were selected from the MISO MTEP19 study; switching sequences for local contingencies were developed based on the generic clearing times shown in Table 7-3. The admittance for local single line-to-ground (SLG) faults were estimated by assuming that the Thevenin impedance of the positive, negative and zero sequence networks at the fault point are equal.

Table 7-2: Regional and Local Disturbance Descriptions

CEII Redacted

Table 7-3: Generic Clearing Time Assumption

Voltage Level (kV)	Primary Clearing Time (cycle)	Backup Clearing Time (cycle)
345 kV	4	11
230 kV	5	13
161/138 kV	6	18
115 kV	6	20
69 kV	8	24

7.4 Performance Criteria

MISO transient stability criteria and local TOs' planning criteria specified in MTEP19 were adopted. All generators must mitigate the stability constraints to obtain any type of Interconnection Service.

7.5 Summer Peak Stability Results

The contingencies listed in Table 7-2 were simulated using the summer peak stability case without any steady state ERIS Network Upgrades identified in DPP 2018 April Phase 2.

Appendix H.1.2 contains plots of generator rotor angles, generator power output, and bus voltages for each simulation. Simulations were performed with a 0.5 seconds steady-state run followed by the appropriate disturbance. Simulations were run for a 10-second duration.

Summer peak stability study results summary is in Appendix H.1.1, **Table H-1**.

The following stability related issues were identified in the summer peak stability study.

7.5.1 Zone 1 Distance Relay Tripping

Under the 3-phase bus faults listed in Table 7-4, several zone 1 distance relays took tripping actions before the close-in 3-phase bus faults were cleared. In addition, under the fault of “GRANT_3ph_MITCHELL_115 “, zone 1 distance relay at bus Cherry Creek 115 kV (line Cherry Creek – Grant 115 kV) took tripping action due to incorrect zone 1 reach setting (0.371 p.u.) which is larger than the line reactance X=0.1409 p.u..

These zone 1 distance relays were disabled for all stability simulation results in Appendix H.1. No transient stability violations were identified.

Table 7-4: Zone 1 Distance Relay Tripping

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7.5.2 Voltage Recovery Issues in ITCM

Under multiple faults, voltages at several ITCM buses did not recover to above 0.93 p.u. within 1 second after faults were cleared. Per the most recent ITCM Local Planning Criteria (LPC), ITCM bus voltages are required to recover to above 0.93 p.u. within 8 seconds. Therefore, these identified voltage recovery issues are not stability violations.

7.5.3 Transient Voltage Rise at Arnold 161 kV Bus

Under the fault of “2298_w_mec_p55”, transient voltage at Arnold 161 kV bus was above 1.04 p.u. for 1.313 second (>1.0 second threshold). This transient voltage rise can be resolved by resetting generator’s scheduled voltage, turning off capacitor at Arnold 161 kV bus, or adjusting transformer tap position.

7.5.4 Stability Network Upgrades Identified in Summer Peak

In summary, there are no stability Network Upgrades identified in summer peak stability study.

7.6 Summer Shoulder Stability Results

The contingencies listed in Table 7-2 were simulated using the summer shoulder stability case with DPP 2018 April Phase 2 steady state ERIS Network Upgrades (Table 4-3, Table 4-4, Table 4-5) and switched capacitors (Table 7-1) which are required ERIS NUs in DPP 2017 August Phase 2. The zone 1 relays with tripping issues identified in summer peak stability study were disabled. The ITCM voltage recovery duration criterion was updated from 1 second to 8 seconds.

Appendix H.2.2 contains plots of generator rotor angles, generator power output, and bus voltages for each simulation. Simulations were performed with a 0.5 seconds steady-state run followed by the appropriate disturbance. Simulations were run for a 10-second duration.

Summer shoulder stability study results summary is in Appendix H.2.1, Table H-2.

The following stability related issues were identified in the summer shoulder stability study.

7.6.1 Voltage Collapse under Four Faults

Under four faults listed in Table 7-5, transient instability and voltage collapse was identified in Alexandria 345 kV area.

Table 7-5: Voltage Collapse under Four Faults

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With addition of Network Upgrades listed in Table 7-6, the identified transient instability and voltage collapse will be completely mitigated.

Table 7-6: Additional Stability Network Upgrades for Mitigating Voltage Collapse

Network Upgrades	Comments
Two 75 MVAR SVCs at J873 POI 345 kV	DPP 2017 Aug. Ph2 MISO ERIS NU
Two 50 Mvar capacitors at Wahpeton 230 kV	DPP 2017 Aug. Ph2 MISO ERIS NU [1]
Build Alexandria - Twin Brooks 345 kV line	DPP 2017 Aug. Ph2 GRE LPC NU
Four 50 MVAR capacitors at Alexandria 345 kV	DPP 2017 Aug. Ph2 GRE LPC NU [2]
200 MVAR SVC at Wahpeton 230 kV	DPP 2017 Aug. Ph2 GRE LPC NU

Note 1: Six 50 MVAR capacitors at Wahpeton 230 kV are required as DPP 2017 Aug. Phase 2 MISO ERIS NU.

Note 2: Two 75 MVAR capacitor and 200 MVAR SVC at Alexandria 345 kV are required as DPP 2017 Aug. Phase 2 GRE LPC NUs.

7.6.2 Transient Voltage Rise/Drop at Arnold 161 kV Bus

Under multiple faults listed in Table 7-7, transient voltage at Arnold 161 kV bus was above 1.04 p.u. for more than 1.0 second. Under the fault of “1174_x_ce_p12 “, transient voltage at Arnold 161 kV bus dropped to below 0.99 p.u. for more than 1.0 second. The transient voltage rise/drop can be resolved by resetting generator’s scheduled voltage, turning off capacitor at Arnold 161 kV bus, or adjusting transformer tap position.

Table 7-7: Transient Voltage Rise/Drop at Arnold 161 kV Bus

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7.6.3 Stability Network Upgrades Identified in Summer Shoulder

In summary, additional stability Network Upgrades required in summer shoulder stability study are listed in Table 7-8.

Table 7-8: Additional Stability Network Upgrades Required in Summer Shoulder Study

Network Upgrades	Comments
150 MVAR capacitor at Bison 345 kV	DPP 2017 Aug. Ph2 MISO ERIS NU
Three 50 MVAR capacitor at Maple River 230 kV	DPP 2017 Aug. Ph2 MISO ERIS NU
Two 75 MVAR SVCs at J873 POI 345 kV	DPP 2017 Aug. Ph2 MISO ERIS NU

Network Upgrades	Comments
Two 50 Mvar capacitors at Wahpeton 230 kV	DPP 2017 Aug. Ph2 MISO ERIS NU [1]
Build Alexandria - Twin Brooks 345 kV line	DPP 2017 Aug. Ph2 GRE LPC NU
Four 50 MVAR capacitors at Alexandria 345 kV	DPP 2017 Aug. Ph2 GRE LPC NU [2]
200 MVAR SVC at Wahpeton 230 kV	DPP 2017 Aug. Ph2 GRE LPC NU

Note 1: Six 50 MVAR capacitors at Wahpeton 230 kV are required as DPP 2017 Aug. Phase 2 MISO ERIS NU.

Note 2: Two 75 MVAR capacitor and 200 MVAR SVC at Alexandria 345 kV are required as DPP 2017 Aug. Phase 2 GRE LPC NUs.

7.7 Additional Network Upgrades Identified in Stability Analysis

Additional Network Upgrades required in the DPP 2018 April Phase 2 stability analysis are listed in Table 7-9. These stability Network Upgrades are required NUs in DPP 2017 August Phase 2 study. Therefore, generation projects in DPP 2018 April West study are not responsible for these Network Upgrades costs.

Table 7-9: Additional Stability Network Upgrades Required in Summer Shoulder Study

Network Upgrades	Comments
150 MVAR capacitor at Bison 345 kV	DPP 2017 Aug. Ph2 MISO ERIS NU
Three 50 MVAR capacitor at Maple River 230 kV	DPP 2017 Aug. Ph2 MISO ERIS NU
Two 75 MVAR SVCs at J873 POI 345 kV	DPP 2017 Aug. Ph2 MISO ERIS NU
Two 50 Mvar capacitors at Wahpeton 230 kV	DPP 2017 Aug. Ph2 MISO ERIS NU [1]
Build Alexandria - Twin Brooks 345 kV line	DPP 2017 Aug. Ph2 GRE LPC NU
Four 50 MVAR capacitors at Alexandria 345 kV	DPP 2017 Aug. Ph2 GRE LPC NU [2]
200 MVAR SVC at Wahpeton 230 kV	DPP 2017 Aug. Ph2 GRE LPC NU

Note 1: Six 50 MVAR capacitors at Wahpeton 230 kV are required as DPP 2017 Aug. Phase 2 MISO ERIS NU.

Note 2: Two 75 MVAR capacitor and 200 MVAR SVC at Alexandria 345 kV are required as DPP 2017 Aug. Phase 2 GRE LPC NUs.

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Section

8

MWEX Voltage Stability Study

ATC performed steady state voltage stability analysis. Voltage stability analysis is required to determine if the initial conditions of the DPP system models under study are in a stable state as defined by Power-Voltage (PV) curves of the Minnesota Wisconsin Export Interface (MWEX) for the worst contingency.

As shown in Table 8-1, the Pre-DPP scenario in the 2024SH case is not voltage stable. The Pre-DPP scenario does not converge with the worst contingency and therefore is in violation of ATC Planning Criteria.

The Post-DPP scenario in the 2024SH case is voltage stable but is also in violation of ATC Planning Criteria because the voltage stability margin is less than 10% with the worst contingency.

However, because the Post-DPP scenario is not aggravating the criteria violations, Network Upgrades related to voltage stability will not be assigned to the Interconnection Customers, based on the assumptions used in this analysis.

The MWEX voltage stability study details can be found in Appendix I.

Table 8-1: MWEX Margins to Collapse in the 2024SH Cases

	Real Power Flow (MW)						
	AHD-SLK[1]	MWEX			Margin to Nose[2]		
Case	N-0 Initial Condition	N-0 I.C.[3]	N-1 I.C.[3]	N-1 Nose	(MW)	(%)	Notes
Pre-DPP	494.5	1249.7	N/A – Contingency does not converge [6]				Voltage Unstable
Post-DPP	517.4	1295.8	664.7	727.2	62.5	8.6	Voltage Stable Insufficient Margin[4a] Vnose > Vmin[4b]

Notes:

1. As described in the active MWEX Operating Guide, the AHD-SLK interface is a single element Power Transfer Distribution Factor (PTDF) interface measured at the Minnesota Power 230 kV side of the Arrowhead 230 kV phase shifter.
2. Margin to Nose is defined as:
   a. "Margin to Nose (MW)" = "MWEX N-1 Nose" – "N-1 Initial Condition After Phase Shift"
   b. "Margin to Nose (%)" = "Margin to Nose (MW)" / "MWEX N-1 Nose"
3. Initial Condition flows were measured in the base cases with an intact system and the worst contingency, plus operation of various control systems as needed with all transformer taps, switched shunts, and PARs locked. The

worst contingency for the Bench case is different than the worst contingency for the Study case because three contingencies did not converge in the Base case

4. ATC Planning Criteria requires:
    a. A 10% voltage stability margin.
    b. Vnose < Vmin.

Section

9

Short Circuit Analysis

Siemens PTI and several transmission owning companies performed short circuit analysis for the DPP 2018 April West study cycle projects.

9.1 J952 Short Circuit Study

The J952 short circuit study was performed by Siemens PTI. The study show that the 3PH fault current is 1,360 A (increased by 349 A) and SLG fault current is 1,542 A (increased by 635 A) at the J952 POI 115 kV bus. Based on the Transmission Owner's short circuit criteria, interconnection of the J952 generation project does not cause any Transmission Owner short circuit constraints.

Study details can be found in Appendix J.1.

9.2 J959 Short Circuit Study

The J959 short circuit study was performed by SMMPA. The study results show that the 3PH fault current is 7138.7 A (increased by 1156.7 A) and the SLG fault current is 5888.2 A (increased by 1331.5 A) at the J959 POI 161 kV bus. Based on the results of the study, SMMPA's equipment has adequate interrupting capability to accommodate the interconnection project J959. Equipment not owned by SMMPA was not evaluated for interrupting capability.

Study details can be found in Appendix J.2.

9.3 J967 & J1072 Short Circuit Study

The J967 & J1072 short circuit study was performed by Siemens PTI. The study results show that the 3PH fault current is 15,468 A (increased by 706 A) and SLG fault current is 13,582 A (increased by 1,527 A) at the Adams 345 kV bus. Based on the Transmission Owner's short circuit criteria, interconnection of the J967 and J1072 generation project does not cause any Transmission Owner short circuit constraints.

Study details can be found in Appendix J.3.

9.4 J975 Short Circuit Study

The J975 short circuit study was performed by OTP. Based on the short circuit analysis performed, the fault current ratings of the Transmission Owner's equipment in the area are not exceeded and there are no upgrades required. With the proposed projects additions, the fault currents are roughly 11.8 kA at the Buffalo 115 kV bus. There does not appear to be any short circuit related upgrades needed for the projects. The Transmission Owner did not evaluate any impacts on the fault-current levels at substations owned by other Transmission Owners.

Study details can be found in Appendix J.4.

9.5 J981 Short Circuit Study

The J981 short circuit study was performed by Siemens PTI. The study results show that the 3PH fault current is 16,719 A (increased by 755 A) and SLG fault current is 13,392 A (increased by 1,689 A) at the Sub T HSK 345 kV bus. Based on the Transmission Owner's short circuit criteria, interconnection of the J981 generation project does not cause any Transmission Owner short circuit constraints.

Study details can be found in Appendix J.5.

9.6 J982 Short Circuit Study

The J982 short circuit study was performed by Siemens PTI. The study results show that the 3PH fault current is 11,657 A (increased by 1,085 A) and SLG fault current is 10,104 A (increased by 2,018 A) at the J982 POI 345 kV bus. Based on the Transmission Owner's short circuit criteria, interconnection of the J982 generation project does not cause any Transmission Owner short circuit constraints.

Study details can be found in Appendix J.6.

9.7 J1001 Short Circuit Study

The J1001 short circuit study was performed by Siemens PTI. The study results show that the 3PH fault current is 10,279 A (increased by 266 A) and SLG fault current is 11,156 A (increased by 180 A) at the Buffalo Ridge 115 kV bus. Based on the Transmission Owner's short circuit criteria, interconnection of the J1001 generation project does not cause any Transmission Owner short circuit constraints.

Study details can be found in Appendix J.7.

9.8 J1024 Short Circuit Study

The J1024 short circuit study was performed by Siemens PTI. The study results show that the 3PH fault current is 9,980 A (increased by 1772 A) and SLG fault current is 7,838 A (increased by 889 A) at the Bradyville 161 kV facility. Based on the Transmission Owner's short circuit criteria, interconnection of the J1024 generation project does not cause any Transmission Owner short circuit constraints.

Study details can be found in Appendix J.8.

9.9 J1040 Short Circuit Study

The J1040 short circuit study was performed by Siemens PTI. The study results show that the 3PH fault current is 6,276 A (increased by 1,119 A) and SLG fault current is 6,188 A (increased by 1,689 A) at the Wishek 230 kV bus. Based on the Transmission Owner's short circuit criteria, interconnection of the J1040 generation project does not cause any Transmission Owner short circuit constraints.

Study details can be found in Appendix J.9.

9.10 J1045 Short Circuit Study

The J1045 short circuit study was performed by Siemens PTI. The study results show that the 3PH fault current is 10,632 A (increased by 162 A) and SLG fault current is 12,005 A (increased by 162 A) at the J874 substation (J874SUB) 115 kV bus. Based on the Transmission Owner's short circuit criteria, interconnection of the J1045 generation project does not cause any Transmission Owner short circuit constraints.

Study details can be found in Appendix J.10.

9.11 J1050 Short Circuit Study

The J1050 short circuit study was performed by ITCM. Based on the analysis performed, ITC Midwest equipment has adequate interrupting capability to accommodate the interconnection of Project J1050. Equipment not owned by ITC Midwest was not evaluated for interrupting capability.

Study details can be found in Appendix J.11.

9.12 J1084 Short Circuit Study

The J1084 short circuit study was performed by ITCM. Based on the analysis performed, ITC Midwest equipment has adequate interrupting capability to accommodate the interconnection of Project J1084. Equipment not owned by ITC Midwest was not evaluated for interrupting capability.

Study details can be found in Appendix J.12.

9.13 J1092 Short Circuit Study

The J1092 short circuit study was performed by Siemens PTI. The study results show that the 3PH fault current is 8,781 A (increased by 615 A) and SLG fault current is 8,748 A (increased by 1,763 A) at the Three Lakes 115 kV bus. Based on the Transmission Owner's short circuit criteria, interconnection of the J1092 generation project does not cause any Transmission Owner short circuit constraints.

Study details can be found in Appendix J.13.

9.14 J1098 Short Circuit Study

The J1098 short circuit study was performed by Siemens PTI. The study results show that the 3PH fault current is 16,855 A (increased by 94 A) and SLG fault current is 17,419 A (increased by 92 A) at the Trimont wind farm 345 kV bus ("TRW_345KV_1"). Based on the Transmission Owner's short circuit criteria, interconnection of the J1098 generation project does not cause any Transmission Owner short circuit constraints.

Study details can be found in Appendix J.14.

9.15 J1105 Short Circuit Study

The J1105 short circuit study was performed by Siemens PTI. The study results show that the 3PH fault current is 23,919 A (increased by 438 A) and SLG fault current is 19,815 A (increased by 1486 A) at the Hampton Corners 345 kV bus. Based on the Transmission Owner's short circuit criteria, interconnection of the J1105 generation project does not cause any Transmission Owner short circuit constraints.

Study details can be found in Appendix J.15.

9.16 J1106 Short Circuit Study

The J1106 short circuit study was performed by Xcel. The study results show that the 3PH fault current is 10,756 A (increased by 629 A) and SLG fault current is 8,645 A (increased by 276 A) at the J1106 POI 345 kV bus. Based on the Transmission Owner's short circuit criteria, interconnection of the J1106 generation project does not cause any Transmission Owner short circuit constraints.

Study details can be found in Appendix J.16.

9.17 J1110 Short Circuit Study

The J1110 short circuit study was performed by SMMPA. The study results show that in the study case, 3PH fault current is 13220 Amps (increased by 771 Amps) and SLG fault current is 11182 Amps (increased by 2118 Amps) at the J1128 POI 161 kV bus. Based on the results of the study, SMMPA's and DPC's equipment have adequate interrupting capability to accommodate the interconnection project J1110. Equipment not owned by SMMPA or DPC was not evaluated for interrupting capability.

Study details can be found in Appendix J.17.

9.18 J1122 Short Circuit Study

The J1122 short circuit study was performed by Siemens PTI. The study results show that the 3PH fault current is 13,062 A (increased by 780 A) and SLG fault current is 11,278 A (increased by 1,626 A) at the J1122 POI 345 kV bus. Based on the Transmission Owner's short circuit criteria, interconnection of the J1122 generation project does not cause any Transmission Owner short circuit constraints.

Study details can be found in Appendix J.18.

9.19 J1124 Short Circuit Study

The J1124 short circuit study was performed by Siemens PTI. The study results show that the 3PH fault current is 17,177 A (increased by 232 A) and SLG fault current is 14,751 A (increased by 823 A) at the Byron 345 kV bus. Based on the Transmission Owner's short circuit criteria, interconnection of the J1124 generation project does not cause any Transmission Owner short circuit constraints.

Study details can be found in Appendix J.19.

9.20 J1128 Short Circuit Study

The J1128 short circuit study was performed by SMMPA. The study results show that in the study case, 3PH fault current is 13219.5 Amps (increased by 770.9 Amps) and SLG fault current is 11181.9 Amps (increased by 2118.4 Amps) at the J1128 POI 161 kV bus. Based on the results of the study, SMMPA's equipment has adequate interrupting capability to accommodate the interconnection project J1128. Equipment not owned by SMMPA was not evaluated for interrupting capability.

Study details can be found in Appendix J.20.

9.21 J1131 Short Circuit Study

The J1131 short circuit study was performed by Siemens PTI. The study results show that the 3PH fault current is 29,870 A (increased by 668 A) and SLG fault current is 25,426 A (increased by 290 A) at the Sub 56 161 kV facility. Based on the Transmission Owner's short circuit criteria, interconnection of the J1131 generation project does not cause any Transmission Owner short circuit constraints.

Study details can be found in Appendix J.21.

9.22 J1132 Short Circuit Study

The J1132 short circuit study was performed by ITCM. Based on the analysis performed, ITC Midwest equipment has adequate interrupting capability to accommodate the interconnection of Project J1132. Equipment not owned by ITC Midwest was not evaluated for interrupting capability.

Study details can be found in Appendix J.22.

9.23 J1135 Short Circuit Study

The J1135 short circuit study was performed by ITCM. Based on the analysis performed, ITC Midwest equipment has adequate interrupting capability to accommodate the interconnection of Project J1135. Equipment not owned by ITC Midwest was not evaluated for interrupting capability.

Study details can be found in Appendix J.23.

9.24 J1140 Short Circuit Study

The J1140 short circuit study was performed by MP. When considering breaker margins for all circuit breakers under study, no violations of breaker interrupting capabilities are expected. Because of this, no mitigation for short circuit studies are required by Minnesota Power for MISO project J1140.

Study details can be found in Appendix J.24.

9.25 J1164 Short Circuit Study

The J1164 short circuit study was performed by ITCM. Based on the analysis performed, ITC Midwest equipment has adequate interrupting capability to accommodate the interconnection of Project J1164. Equipment not owned by ITC Midwest was not evaluated for interrupting capability.

Study details can be found in Appendix J.25.

9.26 J1169 Short Circuit Study

The J1169 short circuit study was performed by Siemens PTI. The study results show that the 3PH fault current is 4,286 A (increased by 423 A) and SLG fault current is 2,970 A (increased by 208 A) at the Grant 115 kV bus. Based on the Transmission Owner's short circuit criteria, interconnection of the J1169 generation project does not cause any Transmission Owner short circuit constraints.

Study details can be found in Appendix J.26.

9.27 J1174 & J1175 Short Circuit Study

The J1174 and J1175 short circuit study was performed by ITCM. Based on the analysis performed, ITC Midwest equipment has adequate interrupting capability to accommodate the interconnection of Projects J1174 and J1175. Equipment not owned by ITC Midwest was not evaluated for interrupting capability.

Study details can be found in Appendix J.27.

9.28 J1181 Short Circuit Study

The J1181 short circuit study was performed by ITCM. Based on the analysis performed, ITC Midwest equipment has adequate interrupting capability to accommodate the interconnection of Project J1181. Equipment not owned by ITC Midwest was not evaluated for interrupting capability.

Study details can be found in Appendix J.28.

9.29 J1187 Short Circuit Study

The J1187 short circuit study was performed by GRE. Fault currents were calculated before and after the addition of J1187's 151.8 MW of wind generation. The results show that none of the circuit breaker interrupting capabilities at Stanton, McHenry, Coal Creek, and Balta substations will be exceeded after the addition of J1187. Based on the Transmission Owner's short circuit criteria, interconnection of the J1187 generation project does not cause any Transmission Owner short circuit constraints.

Study details can be found in Appendix J.29.

Section

10

Deliverability Study

10.1 Project Description

Interconnection requests requesting Network Resource Interconnection Services (NRIS) were considered for deliverability analysis.

10.2 Introduction

Generator interconnection projects must pass Generator Deliverability Study to be granted Network Resource Interconnection Services (NRIS).

If the generator is determined as not fully deliverable, the customer can choose either to change his project to an Energy Resource (ER) project or proceed with the system upgrades that will make the generator fully deliverable.

Generator Deliverability Study ensures that the Network Resources, on an aggregate basis, can meet the MISO aggregate load requirements during system peak condition without getting bottled up. The wind generators are tested at 100 % of their maximum output level which then can be used to meet Resource Adequacy obligations, under Module E, of the MISO Transmission and Energy Market Tariff (TEMT).

10.3 Study Methodology

MISO Generation Deliverability Study method can be found in Appendix C of the MISO Generation Interconnection Business Practices Manual BPM-015-r22.

10.4 2024 Deliverability Study Result

10.4.1 J953

J953 Deliverable (NRIS) Amount in 2024 case: (Conditional on ERIS and IC upgrades and case assumptions)	**1.83 MW (100%)**

10.4.2 J954

J954 Deliverable (NRIS) Amount in 2024 case: (Conditional on ERIS and IC upgrades and case assumptions)	**1.4 MW (100%)**

10.4.3 J959

J959 Deliverable (NRIS) Amount in 2024 case: (Conditional on ERIS and IC upgrades and case assumptions)	**150 MW (100%)**

10.4.4 J963

J963 Deliverable (NRIS) Amount in 2024 case: (Conditional on ERIS and IC upgrades and case assumptions)	**9 MW (100%)**

10.4.5 J967

J967 Deliverable (NRIS) Amount in 2024 case: (Conditional on ERIS and IC upgrades and case assumptions)	**150 MW (100%)**

10.4.6 J981

J981 Deliverable (NRIS) Amount in 2024 case: (Conditional on ERIS and IC upgrades and case assumptions)	200 MW (100%)

10.4.7 J982

J982 Deliverable (NRIS) Amount in 2024 case: (Conditional on ERIS and IC upgrades and case assumptions)	300 MW (100%)

10.4.8 J1001

J1001 Deliverable (NRIS) Amount in 2024 case: (Conditional on ERIS and IC upgrades and case assumptions)	40 MW (100%)

10.4.9 J1024

J1024 Deliverable (NRIS) Amount in 2024 case: (Conditional on ERIS and IC upgrades and case assumptions)	0 MW (0%)						
Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	**Level of service Attainable (MW)**	**Distribution Factor**	**Constraint in ERIS Analysis?**	**Projects Associated with ERIS Constraint**	**Projects Associated with NRIS Constraint**	**Upgrade Costs Allocated to Project**	**Total Cost of Upgrade**
Reconductor MCKSBRG-Winterset	0.00	0.1682	No		J1024, J1132	$6,367,594	$10,000,000
Council Bluffs-S3456 345 kV Terminal Equipment Upgrade	109.95	0.1250	No		J1024, J1050, J1122, J1132	$31,263	$200,000
Winterset-Norwalk Structure Replacements	134.64	0.1417	No		J1024, J1132	$189,586	$300,000

J1024 Deliverable (NRIS) Amount in 2024 case: (Conditional on ERIS and IC upgrades and case assumptions)	0 MW (0%)						
Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	**Level of service Attainable (MW)**	**Distribution Factor**	**Constraint in ERIS Analysis?**	**Projects Associated with ERIS Constraint**	**Projects Associated with NRIS Constraint**	**Upgrade Costs Allocated to Project**	**Total Cost of Upgrade**
Adams-Creston Structure Replacements	200.00	0.2663	No		J1024	$800,000	$800,000

10.4.10 J1040

J1040 Deliverable (NRIS) Amount in 2024 case: (Conditional on ERIS and IC upgrades and case assumptions)	250 MW (100%)

10.4.11 J1045

J1045 Deliverable (NRIS) Amount in 2024 case: (Conditional on ERIS and IC upgrades and case assumptions)	20 MW (100.0%)

10.4.12 J1050

J1050 Deliverable (NRIS) Amount in 2024 case: (Conditional on ERIS and IC upgrades and case assumptions)	0 MW (0%)						
Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	**Level of service Attainable (MW)**	**Distribution Factor**	**Constraint in ERIS Analysis?**	**Projects Associated with ERIS Constraint**	**Projects Associated with NRIS Constraint**	**Upgrade Costs Allocated to Project**	**Total Cost of Upgrade**
Council Bluffs-S3456 345 kV Terminal Equipment Upgrade	225	0.0652	No		J1024, J1050, J1122, J1132	$18,345	$200,000

10.4.13 J1072

J1072 Deliverable (NRIS) Amount in 2024 case: (Conditional on ERIS and IC upgrades and case assumptions)	150 MW (100%)

10.4.14 J1084

J1084 Deliverable (NRIS) Amount in 2024 case: (Conditional on ERIS and IC upgrades and case assumptions)	150 MW (100%)

10.4.15 J1092

J1092 Deliverable (NRIS) Amount in 2024 case: (Conditional on ERIS and IC upgrades and case assumptions)	100 MW (100%)

10.4.16 J1098

J1098 Deliverable (NRIS) Amount in 2024 case: (Conditional on ERIS and IC upgrades and case assumptions)	0 MW (0%)						
Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	**Level of service Attainable (MW)**	**Distribution Factor**	**Constraint in ERIS Analysis ?**	**Projects Associated with ERIS Constraint**	**Projects Associated with NRIS Constraint**	**Upgrade Costs Allocated to Project**	**Total Cost of Upgrade**
Second Webster 345/115 kV Transformer	40	0.0587	No		J1098	$10,000,000	$10,000,000

10.4.17 J1105

J1105 Deliverable (NRIS) Amount in 2024 case: (Conditional on ERIS and IC upgrades and case assumptions)	200 MW (100%)

10.4.18 J1106

J1106 Deliverable (NRIS) Amount in 2024 case: (Conditional on ERIS and IC upgrades and case assumptions)	414 MW (100%)

10.4.19 J1110

J1110 Deliverable (NRIS) Amount in 2024 case: (Conditional on ERIS and IC upgrades and case assumptions)	100 MW (100%)

10.4.20 J1122

J1122 Deliverable (NRIS) Amount in 2024 case: (Conditional on ERIS and IC upgrades and case assumptions)	0 MW (0%)						
Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	**Level of service Attainable (MW)**	**Distribution Factor**	**Constraint in ERIS Analysis?**	**Projects Associated with ERIS Constraint**	**Projects Associated with NRIS Constraint**	**Upgrade Costs Allocated to Project**	**Total Cost of Upgrade**
Council Bluffs-S3456 345 kV Terminal Equipment Upgrade	200	0.5792	No		J1024, J1050, J1122, J1132	$144,859	$200,000

10.4.21 J1124

J1124 Deliverable (NRIS) Amount in 2024 case: (Conditional on ERIS and IC upgrades and case assumptions)	100 MW (100%)

10.4.22 J1128

J1128 Deliverable (NRIS) Amount in 2024 case: (Conditional on ERIS and IC upgrades and case assumptions)	150 MW (100%)

10.4.23 J1131

J1131 Deliverable (NRIS) Amount in 2024 case: (Conditional on ERIS and IC upgrades and case assumptions)	100 MW (100%)

10.4.24 J1132

J1132 Deliverable (NRIS) Amount in 2024 case: (Conditional on ERIS and IC upgrades and case assumptions)	0 MW (0%)						
Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	**Level of service Attainable (MW)**	**Distribution Factor**	**Constraint in ERIS Analysis?**	**Projects Associated with ERIS Constraint**	**Projects Associated with NRIS Constraint**	**Upgrade Costs Allocated to Project**	**Total Cost of Upgrade**
Reconductor MCKSBRG-Winterset	0.00	0.3838	No		J1024, J1132	$3,632,406	$10,000,000
Council Bluffs-S3456 345 kV Terminal Equipment Upgrade	27.49	0.0885	No		J1024, J1050, J1122, J1132	$5,533	$200,000
Winterset-Norwalk Structure Replacements	50.00	0.3301	No		J1024, J1132	$110,414	$300,000

10.4.25 J1135

J1135 Deliverable (NRIS) Amount in 2024 case: (Conditional on ERIS and IC upgrades and case assumptions)	50 MW (100%)

10.4.26 J1140

J1140 Deliverable (NRIS) Amount in 2024 case: (Conditional on ERIS and IC upgrades and case assumptions)	80 MW (100%)

10.4.27 J1164

J1164 Deliverable (NRIS) Amount in 2024 case: (Conditional on ERIS and IC upgrades and case assumptions)	80 MW (100%)

10.4.28 J1169

J1169 Deliverable (NRIS) Amount in 2024 case: (Conditional on ERIS and IC upgrades and case assumptions)	50 MW (100%)

10.4.29 J1174

J1174 Deliverable (NRIS) Amount in 2024 case: (Conditional on ERIS and IC upgrades and case assumptions)	165 MW (100%)

10.4.30 J1175

J1175 Deliverable (NRIS) Amount in 2024 case: (Conditional on ERIS and IC upgrades and case assumptions)	165 MW (100%)

10.4.31 J1181

J1181 Deliverable (NRIS) Amount in 2024 case: (Conditional on ERIS and IC upgrades and case assumptions)	200 MW (100%)

10.4.32 J1187

J1187 Deliverable (NRIS) Amount in 2024 case: (Conditional on ERIS and IC upgrades and case assumptions)	**0 MW (0%)**						
Next Upgrade for Higher NRIS Level (cumulative) (i.e. All upgrades must be made for 100% NRIS)	**Level of service Attainable (MW)**	**Distribution Factor**	**Constraint in ERIS Analysis?**	**Projects Associated with ERIS Constraint**	**Projects Associated with NRIS Constraint**	**Upgrade Costs Allocated to Project**	**Total Cost of Upgrade**
2nd Coyote 345/115 kV Transformer	0.00	0.0831	No		J1187	$7,000,000	$7,000,000
New Square Butte-Mandan 230 kV Line	0.00	0.2721	No		J1187	$31,000,000	$31,000,000
East Bismark Terminal Upgrades	151.80	0.0625	No		J1187	$100,000	$100,000

Section

11

Shared Network Upgrades Analysis

Shared Network Upgrade (SNU) test for Network Upgrades driven by higher queued interconnection project was performed for this System Impact Study.

No SNUs were identified in this study.

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Section

12

Cost Allocation

The cost allocation of Network Upgrades for the study group reflects responsibilities for mitigating system impacts based on Interconnection Customer-elected level of Network Resource Interconnection service as of the draft System Impact Study report date.

12.1 Cost Assumptions for Network Upgrades

The cost estimate for each network upgrade was provided by the corresponding transmission owning company.

12.2 ERIS Network Upgrades Proposed for DPP West Area Projects

Network upgrades for Energy Resource Interconnection Service (ERIS) were identified in the MISO ERIS analysis, LPC analyses, and the affected system analysis. The ERIS network upgrades include voltage network upgrades and thermal network upgrades identified in the MISO steady-state analysis, network upgrades identified in the Local Planning Criteria analysis and affected system analysis, voltage network upgrades identified in the MWEX voltage stability analysis, stability network upgrades identified in the MISO transient stability analysis, and short circuit network upgrades identified in the MISO short circuit analysis. The total costs of ERIS network upgrades for the 2024 scenario are summarized in Table 12-1.

Table 12-1: Summary of ERIS Network Upgrades

Category of Network Upgrades	Cost ($)
Base Case Network Upgrades	$210,829,263
Network Upgrades Identified in MWEX Voltage Stability analysis	$0
Additional Thermal Network Upgrades Identified in MISO Steady-State Analysis	$281,330,000
Additional Reactive Power Network Upgrades for Voltage Constraints	$2,000,000
Network Upgrades Identified in Stability Analysis	$0
Network Upgrades Identified in Short Circuit Analysis	$0
Network Upgrades Identified in GRE LPC Analysis	$2,500,000
Network Upgrades Identified in OTP LPC Analysis	$0
Network Upgrades Identified in MDU LPC Analysis	$48,400,000
Network Upgrades Identified in CIPCO affected system	$2,088,000
Network Upgrades Identified in MPC affected system	$8,100,000
Network Upgrades Identified in PJM affected system	$29,750,000

Category of Network Upgrades	Cost ($)
Network Upgrades Identified in AECI affected system	$0
Network Upgrades Identified in SPP affected system	$57,530,140
Shared Network Upgrades	$0
Total	**$642,527,403**

ERIS network upgrades are listed below.

Table 12-2: Network Upgrades Required for Mitigating Voltage Collapse and Severe Thermal Overloads

NUs	Needs	Miles	Cost ($)
Hazel Creek-Scott County 345 kV	Base Case NU	115	$210,829,263
Big Stone South-Twin Brooks 345 kV 2nd Circuit	DPP 2017 Aug. Ph2 NU	30.25	$54,500,000[1]
New J628 POI– Prairie 230 kV 2nd Circuit	DPP 2017 Aug. Ph2 NU	11	$22,360,000[1]

Note 1: The cost is currently assigned to projects in DPP 2017 Aug. Phase 2 cycle. The NU cost may be assigned to DPP 2018 Apr. projects if projects in DPP 2017 Aug. are withdrawn.

Table 12-3: Network Upgrades Required for MWEX Voltage Stability

NUs	Miles	Cost ($)
No MWEX NUs		$0

Table 12-4: Additional Thermal Network Upgrades in MISO Steady-State Analysis

Constraint	Owner	Mitigation	Cost ($)
J1024 POI-Clarinda 161 kV	MEC	MEC: substation terminal equipment upgrades. New rating predicted to be 410 MVA.	$700,000
J1181 POI-Hazleton 345 kV	MEC ITCM	MEC: MEC owns portion of line conductor. Structure replacements. New MEC Only rating expected to be 1094/1094 MVA. $600,000 ITCM: ITCM records show a rating of 1006 MVA summer. $0	$600,000
J611 POI-Maryville 161 kV	MEC GMO	MEC: Existing MEC only rating expected to be 410 MVA after DPP 2016 AUG West line reconductor network upgrade. GMO: NU is not required unless it is identified as constraint in affected system study.	$0
Wilmarth-Field North 345 kV	XEL	Fieldon-Wilmarth 345 rebuild	$96,300,000

Constraint	Owner	Mitigation	Cost ($)
Wilmarth-Sheas Lake 345 kV	XEL	Wilmarth-Sheas Lake 345 kV Rebuild. NU in DPP 2017 Aug West Ph2	$0[1]
Split Rock-White 345 kV	XEL WAPA	XEL: Limiter is on WAPA facility. $0 WAPA: NU is not required unless it is identified as constraint in affected system study.	$0
Blue Lake-Scott Co 345 kV	XEL	Blue Lake-Scott County 345 kV Rebuild. NU in DPP 2017 Aug West Ph2	$0[1]
Field South-Field North 345 kV	XEL	bypassing the Fieldon series cap	$500,000
Field South-Crandal 345 kV	XEL	Crandal-Fieldon 345 kV Rebuild. NU in DPP 2017 Aug West Ph2	$0[1]
Lyon Co-Hazel Creek 345 kV	XEL	Upgrade some sub equipment at Hazel that would put the rating to 1790 MVA normal and emergency	$200,000
Helena-Sheas Lk 345 kV	XEL	Helena-Sheas Lake 345 kV Rebuild. NU in DPP 2017 Aug West Ph2	$0[1]
Sheyenne-Lake Park 230 kV	XEL MPC OTP	Sheyenne-Lake Park 230 kV Uprate. NU in DPP 2017 Aug West Ph2	$0[1]
Sheyenne-Mapleton 115 kV	XEL OTP	Sheyenne-Mapleton 115 kV Rebuild. NU in DPP 2017 Aug West Ph2	$0[1]
M.E. International-Westwood 115 kV	XEL GRE	XEL: Rebuild ME International to Westwood tap (2.1 miles) with 795 ACSS conductor and replace line switches. $5,000,000 GRE: XEL facility	$5,000,000
Austin-Murphy 161 kV	SMMPA	Austin-Murphy Creek 161 kV Rebuild. NU in DPP 2017 Aug West Ph2	$0[1]
Murphy-J1128 POI 161 kV	SMMPA	Murphy Creek – Hayward 161 kV Rebuild. NU in DPP 2017 Aug West Ph2	$0[1]
Hubbard-Badoura 230 kV	MP	Increase conductor clearance for 55C operation (15 miles)	$1,350,000
West St. Cloud-Westwood 115 kV	GRE XEL	Rebuild 0.6 mi to 2x795 ACSS	$900,000
Chub Lake 345-115-34.5 kV xfmr	GRE	Add second 345/115 kV transformer at Chub Lake	$11,400,000
STSTPHNT-Fishill 115 kV	GRE	GRE: XEL owns equipment and line. $0 XEL: Uprate line to 795 ACSS. $5.1M	$5,100,000
CSLTNET-Mapleton 115 kV	OTP	CSLTNET-Mapleton 115 kV Uprate. LPC NU in DPP 2017 Aug West Ph2	$0[1]
Buffalo 345-230-41.6 kV xfmr #2	OTP	Replace Buffalo transformer #2 with larger unit.	$3,000,000
Hankinson-Forman 230 kV	OTP	Hankinson-Forman 230 kV Uprate. LPC NU in DPP 2017 Aug West Ph2	$0[1]
Wahpeton-Fergus Falls 230 kV	OTP MRES	Wahpeton-Fergus Falls 230 kV Uprate. NU in DPP 2017 Aug West Ph2	$0[1]

Constraint	Owner	Mitigation	Cost ($)
Audubon-Lake Park 230 kV	OTP	Audubon-Lake Park 230 kV Uprate. NU in DPP 2017 Aug West Ph2	$0[1]
Big Stone South 345-230-34.5 kV #1	OTP	Big Stone South Transformer #1 Upgrade. LPC NU in DPP 2017 Aug West Ph2	$0[1]
Big Stone South 345-230-34.5 kV #2	OTP	Big Stone South Transformer #2 Upgrade. LPC NU in DPP 2017 Aug West Ph2	$0[1]
Ellendale-County Line 69 kV	ITCM	Rebuild 5.79 miles	$4,200,000
Hayward-County Line 69 kV	ITCM	Rebuild 13.32 miles	$9,700,000
Osceola-Osceola REC 69 kV	ITCM CIPCO	ITCM: ITCM rating 42/44 MVA SN/SE CIPCO: NU is not required unless identified in affected system study	$0
Adams-Hayward 161 kV	ITCM	Adams-Hayward 161 kV Uprate. NU in DPP 2017 Aug West Ph2	$0[1]
Hazleton-Arnold 345 kV	ITCM MEC	MEC: MEC owns a portion of line conductor. Structure replacements. New MEC Only rating expected to be 1139/1139 MVA. $800K ITCM: Structure replacements. New ITCM rating 1285 MVA/SN/SE. $480K	$1,280,000
Adams-Creston 161 kV	MEC WAPA	Structure replacements. New rating expected to be 182/182 MVA	$800,000
Webster-Wright 161 kV	MEC	Reconductor line and substation terminal equipment upgrades. New rating predicted to be 315/335 MVA.	$8,000,000
Franklin-Wall Lake 161 kV	MEC	Reconductor line. New rating predicted to be 335/335 MVA.	$12,000,000
Wilton-Winger 230 kV	MPC OTP	OTP: Sufficient for the flows of 395.2 MVA. $0	$0
Ellendale-Aberdeen 115 kV	MDU NWE	Ellendale-Aberdeen Jct 115 kV Uprate. LPC NU in DPP 2017 Aug West Ph2	$0[1]
Heskett-J302 POI 230 kV	MDU	Add a breaker at Merricourt and build 2nd Mandan-Napoleon SW 230 kV line w/ 1272 ACSS (includes river crossing).	$81,500,000
Heskett-Mandan 230 kV	MDU	The Heskett 230 kV sub has an estimated retirement date of 7/23/2021. When the Heskett 230 kV sub is retired, this constraint will no longer exist.	$0
Heskett 230-115-13.8 kV xfmr	MDU	The Heskett 230/115 kV transformer is planned to be moved to Mandan to function in parallel to the existing Mandan 230/115 kV transformer. Once the Heskett 230/115 kV transformer is moved, this constraint will no longer exist.	$0
Mandan-Ward 230 kV	MDU BEPC	MDU's rating at Mandan is 956 MVA. MPC owns equipment at Mandan. WAPA owns the line. BEPC owns Ward.	$0

Constraint	Owner	Mitigation	Cost ($)
Fox Tail-Tatanka North 230 kV	MDU	Major substation upgrades at Tatanka North 230 (new rating: 610/610 MVA [N/E]).	$1,500,000
Fox Tail-Ellendale 230 kV	MDU	Foxtail-Ellendale 230 kV Rebuild. LPC NU in DPP 2017 Aug West Ph2	$0[1]
Merricourt-Wishek 230 kV	MDU	Rebuild/reconductor line with 1272 ACSS (new rating: 797/797 MVA [N/E]).	$15,000,000
Merricourt-Tatanka North 230 kV	MDU	Rebuild line to ACSS. New Rating: 478/478 MVA.	$1,000,000
Merricourt-Ellendale 230 kV	MDU	Rebuild/reconductor Merricourt-Ellendale345 230 kV line w/ 1272 ACSS (new rating: 776/776 MVA [N/E]).	$15,000,000
Wishek-J302 POI 230 kV	MDU	J302 POI-Wishek 230 kV Rebuild. LPC NU in DPP 2017 Aug West Ph2	$0[1]
Wabaco-Rochester 161 kV	DPC	Rebuild line with 795 ACSS conductor. $11M. MTEP Appendix A project	$0[2]
Wabaco-Alma 161 kV	DPC	Rebuild line with 795 ACSS conductor	$6,300,000

Note 1: Costs of Network Upgrades required in DPP 2017 Aug West Ph2 are currently assigned to projects in DPP 2017 Aug. Phase 2 cycle. The NUs cost may be assigned to DPP 2018 Apr. projects if projects in DPP 2017 Aug. are withdrawn.
Note 2: This is approximate $11,000,000 Appendix A project in MTEP that is being disputed.

Table 12-5: Additional Reactive Power NUs Required for Voltage Constraints

Network Upgrades	Owner	Cost ($)
Add 1×40 Mvar switched capacitor at Oakes 230 kV (620362)	OTP	$2,000,000

Table 12-6: Network Upgrades Required for Transient Stability

Network Upgrades	Owner	Cost ($)	Comments
150 MVAR capacitor at Bison 345 kV	XEL	$1,500,000 [3]	DPP 2017 Aug. Ph2 MISO ERIS NU
Three 50 MVAR capacitor at Maple River 230 kV	MPC	$3,000,000 [3]	DPP 2017 Aug. Ph2 MISO ERIS NU
Two 75 MVAR SVCs at J873 POI 345 kV	MEC	$45,000,000 [3]	DPP 2017 Aug. Ph2 MISO ERIS NU
Two 50 MVAR capacitors at Wahpeton 230 kV	OTP	$3,250,000 [3]	DPP 2017 Aug. Ph2 MISO ERIS NU [1]
Build Alexandria - Twin Brooks 345 kV line	OTP MRES	$242,400,000 [3]	DPP 2017 Aug. Ph2 GRE LPC NU
Four 50 MVAR capacitors at Alexandria 345 kV	MRES	$16,000,000 [3]	DPP 2017 Aug. Ph2 GRE LPC NU [2]
200 MVAR SVC at Wahpeton 230 kV	OTP	$25,000,000 [3]	DPP 2017 Aug. Ph2 GRE LPC NU

Note 1: Six 50 MVAR capacitors at Wahpeton 230 kV are required as DPP 2017 Aug. Phase 2 MISO ERIS NU.
Note 2: Two 75 MVAR capacitor and 200 MVAR SVC at Alexandria 345 kV are required as DPP 2017 Aug. Phase 2 GRE LPC NUs.
Note 3: Costs of Network Upgrades required in DPP 2017 Aug West Ph2 are currently assigned to projects in DPP 2017 Aug. Phase 2 cycle. The NUs cost may be assigned to DPP 2018 Apr. projects if projects in DPP 2017 Aug. are withdrawn.

Table 12-7: Network Upgrades in Short Circuit Analysis

Constraint	Owner	Mitigation	Cost ($)
No additional NUs			$0

Table 12-8: J1106 GRE Local Planning Criteria Network Upgrades

Constraint	Owner	Mitigation	Cost ($)
Helena-Chub Lake 345 kV	GRE CAPX	Helena-Chub Lake 2nd Circuit, $34M. NU in DPP 2017 Aug West Ph2	$0 [1]

Note 1: Costs of Network Upgrades required in DPP 2017 Aug West Ph2 are currently assigned to projects in DPP 2017 Aug. Phase 2 cycle. The NUs cost may be assigned to DPP 2018 Apr. projects if projects in DPP 2017 Aug. are withdrawn.

Table 12-9: J1140 GRE Local Planning Criteria Network Upgrades

Constraint	Owner	Mitigation	Cost ($)
No J1140 GRE LPC NUs			$0

Table 12-10: CCS (J1187) GRE Local Planning Criteria Network Upgrades

Constraint	Owner	Network Upgrades	Cost ($)
Voltage collapse in Benchmark Case under CUDC contingencies [1]	GRE	Build 2nd CUDC HVDC bipole	Not Available
Stanton-Leland Olds 230 kV	GRE BEPC	GRE: Replace 4 switches, $2.5M BEPC: Update the line reactor. $900K	$2,500,000

Note 1: Study projects in the DPP 2018 Apr. cycle are not responsible for these Network Upgrades required in the benchmark case.

Table 12-11: OTP Local Planning Criteria Network Upgrades

Constraint	Owner	Mitigation	Cost ($)
Erie Jct-Audubon 230 kV	OTP XEL	With future Erie substation, the rating of this line section will be 360.9 MVA normal & emergency. $0	$0

Table 12-12: MDU Local Planning Criteria Network Upgrades

Constraint	Owner	Mitigation	Cost ($)
Mandan-J302 POI 230 kV #1	MDU	Rebuild Mandan-J302 POI 230 kV line (Ckt '1') with 1272 ACSS conductor (includes river crossing). New rating: 797/824 MVA [N/E]).	$48,400,000

Table 12-13: CIPCO Affected System Network Upgrades

Constraint	Owner	Mitigation	Cost ($)
Murray-I35 Tap 69 kV	CIPCO	Rebuild 5.68 miles with T2-4/0 ACSR at $350k per mile.	$1,988,000
Liberty-Hickory Crk 161 kV	CIPCO ITCM	CIPCO: Replace switches and jumpers ITCM: owns the line	$100,000

Table 12-14: MPC Affected System Network Upgrades

Constraint	Owner	Mitigation	Cost ($)
Drayton 230-115 kV xfmr 1	OTP MPC	Replace Transformer	$2,100,000
Prairie-Walle 230 kV	MPC	Rebuild line to achieve a minimum of 462 MVA	$6,000,000

Table 12-15: PJM Affected System Network Upgrades

Constraint	Owner	Mitigation	Total Cost ($)	DPP Projects
Nelson;B- Electric JCT;R 345 kV	PJM	re-conductor the line, station conductor work and upgrade 2-disconnnect switches	$36,200,000	J981, J982, J1084, J1181

Table 12-16: AECI Affected System Network Upgrades

Constraint	Mitigation Required	Owner	Cost ($)	Generator
Essex-Stoddard 161 kV line	Reconductor the 0.59-mile-long Essex to Stoddard 161 kV line to 954 ASCR	AECI	$861,000	None
Green Forest-Township 69 kV line	Reconductor the 2.44-mile-long Green Forest to Township 69 kV line to 336 ACSR	AECI	$2,895,000	None

Table 12-17: SPP ERIS Constraints Network Upgrades

Monitored Facility	Mitigation
Adams to Creston 161 kV Circuit	Reconductor Adams to Creston 161 kV Circuit
Oahe to Sully Buttes 230 kV Circuit	Oahe to Sully Buttes 230 kV Structure Replacement & Terminal Equipment Upgrade
Whitlock to Glenham 230 kV Circuit	Whitlock to Glenham 230 kV Structure Replacement & Terminal Equipment Upgrade
Bison to Hettinger 230 kV Circuit	Upgrade Terminal Equipment Bison to Hettinger 230 kV Circuit

Table 12-18: SPP NRIS Constraints Network Upgrades

Monitored Facility	Mitigation
Cayler to Wisdom 161 kV Circuit	Cayler to Wisdom 161 kV Structure Replacement
Sheffield to Hampton Tap 161 kV Circuit	Rebuild Sheffield to Hampton Tap 161 kV Circuit
Yankton Jct. to NAPA Jct. 115 kV Circuit	Rebuild Yankton Jct. to NAPA Jct. 115 kV Circuit
Roland to ROLANDTP8 69 kV Circuit	Upgrade Terminal Equipment Roland to ROLANDTP8 69 kV Circuit
ROLDANDTP8 to RADCLIFF8 69 kV Circuit	Upgrade Terminal Equipment ROLDANDTP8 to RADCLIFF8 69 kV Circuit
S3451 to S3454 345 kV Circuit	Upgrade Terminal Equipment S3451 to S3454 345 kV Circuit
S3451 to S3459 345 kV Circuit	Upgrade Terminal Equipment S3451 to S3459 345 kV Circuit
Emery to Sheffield 161 kV Circuit	Rebuild Emery to Sheffield 161 kV Circuit
Franklin to Hampton Tap 161 kV Circuit	Upgrade Terminal Equipment Franklin to Hampton Tap 161 kV Circuit

Table 12-19: Shared Network Upgrades

Network Upgrades	Project Study Cycle	Projects sharing cost	MW Contribution	Total Network Upgrade Cost ($)	Cost Responsibility
No SNUs					$0

12.3 Cost Allocation Methodology

12.3.1 Thermal Network Upgrade Cost Allocation

The costs of thermal Network Upgrades (NU) for a set of generation projects (one or more sub-groups or entire group with identified NU) are allocated based on the MW impact from each project on the constrained facilities in the Study Case. For thermal constraints identified in the shoulder peak scenario, the MW impact is calculated using the shoulder peak post-DPP case. The MW impact on constraints identified in the summer peak scenario is calculated using the summer peak post-DPP case. With all Group Study generation projects dispatched in the Study Case, all thermal constraints will be identified and a distribution factor from each project on each constraint will be obtained.

Thermal NU cost will be allocated based on the pro rata share of the MW impact on all constraints from each project, where MW impact = DF * Gen Output of the project in the model where the constraint occurs. If the Network Upgrade alleviates multiple constrained facilities the cost is allocated based on the sum of the highest MW contribution on all of the constrained elements for the DPP project under contingency. The methodology to determine the cost allocation of thermal NU is:

Project A cost portion of NU = Cost of NU x $\left(\frac{Max(Proj.A\ \text{MW}\ contribution\ \text{on constraint})}{\sum_i Max(Proj.i\ \text{MW}\ contribution\ \text{on constraint})}\right)$

12.3.2 Voltage Network Upgrade Cost Allocation

Voltage NU cost allocation will be determined by the pro rata share of the voltage impact each project has on the most constrained bus under the most constraining contingency. The voltage impact of each project will be calculated by locking all voltage regulating equipment in the model and then backing out each project one at a time to identify each project’s impact to the constraint. In severe instances of voltage collapse where projects cannot be backed out one at a time, they will be added one at a time to determine their impact to the constraint.

12.3.3 Transient Stability Network Upgrade Cost Allocation

Transient stability driven Network Upgrades will be cost allocated based on the pro rata share of the total MW request of all the projects causing instability. The project(s) causing instability will be determined by backing out each project one at a time to identify each project’s impact to the constraint.

12.4 Cost Allocation

The cost allocation of Network Upgrades for the study group reflects responsibilities for mitigating system impacts based on Interconnection Customer-elected level of Network Resource Interconnection service as of the draft System Impact Study report date.

For each thermal constraint, the maximum MW contribution (increasing flow) from each DPP project is calculated. MW contribution from one DPP project is set as zero if the project doesn’t violate DPP reliability criteria for a constrained element.

For voltage network upgrades, generators which degrade voltage at the most constrained bus under the most constraining contingency will be responsible for mitigating these constraints.

Transient stability Network Upgrades are allocated based on projects causing instability. If multiple projects are causing instability, cost allocation will be based on pro rata share of total MW of all projects causing instability.

Additional NRIS Network Upgrades are allocated to the impacting NRIS projects. ERIS Network Upgrades will be allocated to the impacting projects only based on the ERIS results.

The calculated DF results, voltage impact, and MW contribution on each constraint are in Appendix K.1 for the 2024 scenario.

Finally, the cost allocation for each NU is calculated based on the contribution of each generating facility, as detailed in Appendix K.2 for the 2024 scenario.

Assuming all generating facilities in the DPP 2018 April West Area group advance, a summary of the costs for total NUs (NUs for ERIS, NRIS, and Interconnection Facilities) allocated to each generating facility is listed in Table 12-20.

Table 12-20: Summary of Total NU Costs Allocated to Each Generation Project

Project	Max Output (MW)	Total Cost of NU per Project ($)	$/MW	Share %
J952	54	$13,372,223	$247,634	1.59%
J953	1.83	$0	$0	0.00%
J954	1.4	$0	$0	0.00%
J959	150	$5,536,033	$36,907	0.66%
J963	9	$0	$0	0.00%
J967	150	$5,949,588	$39,664	0.71%
J975	150	$5,044,983	$33,633	0.60%
J981	200	$15,153,300	$75,767	1.80%
J982	300	$36,881,551	$122,939	4.37%
J1001	40	$8,309,740	$207,743	0.99%
J1024	200	$30,021,447	$150,107	3.56%
J1040	250	$166,495,661	$665,983	19.74%
J1045	20	$28,489	$1,424	0.00%
J1050	225	$2,458,206	$10,925	0.29%
J1072	150	$2,838,989	$18,927	0.34%
J1084	150	$11,064,462	$73,763	1.31%
J1092	100	$12,473,721	$124,737	1.48%
J1098	40	$107,052,503	$2,676,313	12.69%
J1105	200	$18,236,392	$91,182	2.16%
J1106	414	$158,098,579	$381,881	18.74%
J1110	100	$9,584,825	$95,848	1.14%
J1122	200	$14,181,162	$70,906	1.68%
J1124	100	$4,105,434	$41,054	0.49%
J1128	150	$26,832,826	$178,886	3.18%
J1131	100	$825,000	$8,250	0.10%

Project	Max Output (MW)	Total Cost of NU per Project ($)	$/MW	Share %
J1132	50	$5,966,897	$119,338	0.71%
J1135	50	$0	$0	0.00%
J1140	80	$46,498,533	$581,232	5.51%
J1164	80	$7,683,539	$96,044	0.91%
J1169	50	$7,464,640	$149,293	0.89%
J1174	165	$21,005,102	$127,304	2.49%
J1175	165	$27,689,978	$167,818	3.28%
J1181	200	$23,764,399	$118,822	2.82%
J1187	151.8	$48,817,656	$321,592	5.79%
Total/Average	**4447.0**	**$843,435,861**	**$206,939**	**100.00%**

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Appendix

A

Model Development

A.1 DPP 2018 April Generation Projects

Table A-1: DPP 2018 April West Area Projects

MISO Project Num	State	County	Trans. Owner	Point of Interconnection	ERIS Output	NRIS Output	Fuel Type	Service Type
J952	SD	Corson	MDU	McIntosh Junction 115 kV	54	0	Wind	ERIS
J953	IA	Johnson	ITCM	AMIL.IOW_AFRYT	1.83	1.83	Diesel	External NRIS
J954	IA	Johnson	ITCM	AMIL.IOW_AFRYT	1.4	1.4	Solar	External NRIS
J959	IA	Fayette	SMMPA	Windsor 161 kV	150	150	Wind	NRIS
J963	IA	Cedar	ITCM	Bennett - Graham 69 kV	9	9	Diesel	NRIS
J967	MN	Mower	Xcel	Adams 345 kV	150	150	Wind	NRIS
J975	ND	Cass	OTP	Buffalo 115 kV	150	0	Wind	ERIS
J981	IA	Washington	MEC	Sub T 345 kV	200	200	Wind	NRIS
J982	IA	Dickinson, Emmet	MEC	Obrien County - Kossuth 345 kV	300	300	Wind	NRIS
J1001	MN	Lincoln	Xcel	Buffalo Ridge 115 kV	40	40	Solar	NRIS
J1024	MO	Nodaway	MEC	J611 - Clarinda 161 kV	200	200	Wind	NRIS
J1040	ND	McIntosh	MDU	Wishek Junction 230 kV	250	250	Wind	NRIS
J1045	MN	Murray	Xcel	Fenton - Chanarambie 115 kV	20	20	Battery	NRIS
J1050	IA	Boone, Hamilton	ITCM	Doud Tap 161 kV	225	225	Wind	NRIS
J1072	MN	Mower	Xcel	Adams 345 kV	150	150	Solar	NRIS
J1084	IA	Clinton	ITCM	Rock Creek 345 kV	150	150	Solar	NRIS
J1092	WI	Saint Croix	Xcel	Three Lakes 115 kV	100	100	Solar	NRIS
J1098	MN	Jackson	Xcel	Lakefield 345 kV	40	40	Solar	NRIS
J1105	MN	Dakota	Xcel	Hampton Corners 345 kV	200	200	Solar	NRIS

MISO Project Num	State	County	Trans. Owner	Point of Interconnection	ERIS Output	NRIS Output	Fuel Type	Service Type
J1106	MN	Redwood	Xcel	Lyon County - Cedar Mountain 345 kV	414	414	Wind	NRIS
J1110	MN	Mower	SMMPA	North Austin 161 kV	100	100	Solar	NRIS
J1122	IA	Pottawattamie	MEC	Council Bluffs - Fallow Avenue 345 kV	200	200	Wind	NRIS
J1124	MN	Olmsted	SMMPA	Byron 345 kV	100	100	Solar	NRIS
J1128	MN	Freeborn	SMMPA	Hayward - Murphy Creek 161 kV	150	150	Solar	NRIS
J1131	IA	Scott	MEC	Sub 56 161 kV	100	100	Solar	NRIS
J1132	IA	Union	ITCM	Creston East 69 kV	50	50	Solar	NRIS
J1135	IA	Des Moines	ITCM	Huntwoods 69 kV	50	50	Solar	NRIS
J1140	MN	Benton	MP	Langola Tap 115 kV	80	80	Solar	NRIS
J1164	MN	Rock	ITCM	Magnolia 161 kV	80	80	Solar	NRIS
J1169	SD	McCook	Xcel	Grant 115 kV	50	50	Solar	NRIS
J1174	IA	Worth	ITCM	Bison - Colby 345 kV	165	165	Solar	NRIS
J1175	IA	Worth	ITCM	Bison - Colby 345 kV	165	165	Wind	NRIS
J1181	IA	Chickasaw	ITCM	Hazleton - Mitchell county 345 kV	200	200	Wind	NRIS
J1187	ND	Mercer	GRE	Stanton 230 kV	151.8	151.8	Wind	NRIS

Table A-2: Dynamic Modeling, Collector System and Shunt Compensation Modeling for DPP West Area Projects

MISO Project #	Turbine / Inverter	Shunt Compensation	Generator Modeling	Generator Reactive Power Capability	Collector System
J952	15 Vestas V136 3.6 MW	7.2 MVAR	One 54 MW unit	Qmin = - 21.345 MVAR Qmax = + 24.135 MVAR	R = 0.00287 X = 0.00426 B = 0.00906
J959	60 GE 2.5 MW -116	2x9 MVAR	One 150 MW unit	Qmin = - 49.3026 MVAR Qmax = + 49.3026 MVAR	R = 0.007 X = 0.0123 B = 0.04553
J963	3 CAT Diesel 2 MW	None	One 3 MW unit One 6 MW unit	For existing generation Qmin = - 1.4333 MVAR Qmax = + 1.4333 MVAR For CAT Diesel Qmin = - 2.8667 MVAR Qmax = + 2.8667 MVAR	Not Applicable
J967	60 GE 2.5 MW -116	2x14 MVAR	One 150 MW unit	Qmin = - 49.302 MVAR Qmax = + 49.302 MVAR	R = 0.007 X = 0.0123 B = 0.04553
J975	60 GE 2.5 MW -116	1x6 MVAR	One 150 MW unit	Qmin = - 72.648 MVAR Qmax = + 72.648 MVAR	R = 0.00340 X = 0.00490 B = 0.01250
J981	100 Vestas V110 2 MW	2x13.5 MVAR	One 92 MW unit One 108 MW unit	Gen 1: 92 MW Qmin = - 30.238 MVAR Qmax = +30.238 MVAR Gen 2: 108 MW Qmin = - 35.498 MVAR Qmax = +35.498 MVAR	Collector 1: R = 0.03013 X = 0.02732 B = 0.05867 1x13.5 MVAR Cap Collector 2: R = 0.04341 X = 0.03548 B = 0.08374 1x13.5 MVAR Cap
J982	150 Vestas V110 2 MW	2x25.5 MVAR	Two 150 MW units	Gen 1: 150 MW Qmin = - 49.303 MVAR Qmax = + 49.303 MVAR Gen 2: 150 MW Qmin = - 49.303 MVAR Qmax = + 49.303 MVAR	Collector 1: R = 0.02885 X = 0.02659 B = 0.12103 1x25.5 MVAR Cap Collector 2: R = 0.02800 X = 0.02534 B = 0.11000 1x25.5 MVAR Cap

MISO Project #	Turbine / Inverter	Shunt Compensation	Generator Modeling	Generator Reactive Power Capability	Collector System
J1001	11 TMEIC 3.71 MW	1x6 MVAR	One 40 MW unit	Qmin = - 13.142 MVAR Qmax = 13.142 MVAR	R = 0.0018 X = 0.0011 B = 0.0012
J1024	94 Vestas V120 2.2 MW	1x30 MVAR	One 200 MW unit	Qmin = - 67.962 MVAR Qmax = 67.962 MVAR	R = 0.01094 X = 0.00953 B = 0.09425
J1040	100 GE 2.52 MW -127	1*17 MVAR	Two 125 MW units	Gen 1: 125 MW Qmin = - 61.025 MVAR Qmax = 61.025 MVAR Gen 2: 125 MW Qmin = - 61.025 MVAR Qmax = 61.025 MVAR	Collector 1: R = 0.00547 pu X = 0.00639 pu B = 0.02249 pu 1*17 MVAR Cap Collector 2: R = 0.0102 pu X = 0.01436 pu B = 0.03942 pu
J1045	6 4.2 MVA TMEIC Ninja 840KW (5*0.84 MVA) EES	None	One 20 MW unit	Qmin = - 15.33 MVAR Qmax = + 15.33 MVAR	Not Available
J1050	90 GE 2.5 MW -116	4*15 MVAR	Two 112.5 MW units	Gen 1: 112.5 MW Qmin = - 54.4862 MVAR Qmax = + 54.4862 MVAR Gen 2: 112.5 MW Qmin = - 54.4862 MVAR Qmax = + 54.4862 MVAR	Collector 1: R = 0.0054307 pu X = 0.005201 pu B = 0.0505 pu 2*15 MVAR Collector 2: R = 0.009021 pu X = 0.0009061 pu B = 0.0764 pu 2*15 MVAR
J1072	41 TMEIC 4.05 MVA	2*12 MVAR	One 150 MW unit	Qmin = -49.3 MVAR Qmax = +49.3 MVAR	R = 0.0011 pu X = 0.0009 pu B = 0.0054 pu
J1084	41 TMEIC 4.05 MVA	2*12 MVAR	One 150 MW unit	Qmin = -49.3 MVAR Qmax = +49.3 MVAR	R = 0.0011 pu X = 0.0009 pu B = 0.0054 pu
J1092	152 Schneider XC680-NA	1*12 MVAR	One 100 MW unit	Qmax = +48.4 MVAR Qmin = - 48.4 MVAR	R = 0.001858 pu X = 0.001644 pu B = 0.000363 pu
J1098	69 Schneider XC680-NA	None	One 40 MW unit	Qmin = - 19.37 MVAR Qmax = +19.37 MVAR	R = 0.02037 pu X = 0.02274 pu B = 0.02335 pu
J1105	54 TMEIC 4.05 MVA	2*14 MVAR	One 200 MW unit	Qmin = - 65.73 MVAR Qmax = +65.73 MVAR	R = 0.001 pu X = 0.0008 pu B = 0.00820 pu

MISO Project #	Turbine / Inverter	Shunt Compensation	Generator Modeling	Generator Reactive Power Capability	Collector System
J1106	120 Vestas V126 3.45 MW	None	One 414 MW unit	Qmin = - 176.36 MVAR Qmax = + 200.51 MVAR	R = 0.004 pu X = 0.013 pu B = 0.094 pu
J1110	34 Power Electronics HEMK FS3150KU 3.15 MVA	None	One 100 MW unit	Qmin = -48.55 MVAR Qmax = 48.55 MVAR	R = 0.00622 pu X = 0.00846 pu B = 0.02999 pu
J1122	91 Vestas V110 2.2 MW	6 x 10 MVAR capacitor	One 200 MW unit	Qmin = -65.7368 MVAR Qmax = +65.7368 MVAR	R = 0.006 pu X = 0.0074 pu B = 0.1385 pu
J1124	34 Power Electronics HEMK FS3150KU 3.15MVA, 3.276 MVA derated	None	One 100 MW unit	Qmin = -48.55 MVAR Qmax = 48.55 MVAR	R = 0.00622 pu X = 0.00846 pu B = 0.0299 pu
J1128	51 Power Electronics FS3000MU	2X10 MVAR	One 150 MW unit	Qmin = -49.30 MVAR Qmax = 49.30 MVAR	R = 0.003403 pu X = 0.003126 pu B = 0.011686 pu
J1131	34 Power Electronics FS3000CU15	None	One 100 MW unit	Qmin = -59.55 MVAR Qmax = 59.55 MVAR	R = 0.00776 pu X = 0.00951 pu B = 0.02263 pu
J1132	17 Power Electronics FS3000CU15	None	One 50 MW unit	Qmin = -29.7 MVAR Qmax = 29.7 MVAR	R = 0.01593 pu X = 0.01958 pu B = 0.01154 pu
J1135	17 Power Electronics FS3000CU15	None	One 50 MW unit	Qmin = -29.7 MVAR Qmax = 29.7 MVAR	R = 0.00776 pu X = 0.00951 pu B = 0.02263 pu
J1140	30 Power Electronics FS3001CU15	4X6.5 MVAR	One 80 MW unit	Qmin = -26.29 MVAR Qmax = 26.29 MVAR	R = 0.027058 pu X = 0.102788 pu B = 0.023933 pu
J1164	30 Power Electronics FS3001CU15	None	One 80 MW unit	Qmin = - 26.29 MVAR Qmax = 26.29 MVAR	R = 0.0007 pu X = 0.00112 pu B = 0.00046 pu
J1169	18 FS3001CU15	4X4 MVAR	One 50 MW unit	Qmin = - 16.86 MVAR Qmax = 16.86 MVAR	R = 0.005008 pu X = 0.006485 pu B = 0.005161 pu
J1174	62xFS3000 Power Electronics	1x4 MVAR	One 165 MW unit	Qmin = - 79.9 MVAR Qmax = 79.9 MVAR	R = 0.00661 pu X = 0.007671 pu B = 0.0920 pu
J1175	66 GE 2.5 MW -116	1X9 MVAR	One 165 MW unit	Qmin = - 79.9 MVAR Qmax = 79.9 MVAR	R = 0.00661 pu X = 0.007677 pu B = 0.0920 pu
J1181	80 GE 2.5 MW -116	2x6 MVAR	One 200 MW unit	Qmin = - 96.8644 MVAR Qmax = +96.8644 MVAR	R = 0.00340 pu X = 0.0049 pu B = 0.0125 pu

MISO Project #	Turbine / Inverter	Shunt Compensation	Generator Modeling	Generator Reactive Power Capability	Collector System
J1187	69 Vestas V120 2.2 MW	None	One 151.8 MW unit	Qmin = - 49.894 MVAR Qmax = +49.894 MVAR	R = 0.00510 pu X = 0.00530 pu B = 0.02994 pu

Table A-3: DPP 2018 April Central Area Projects

MISO Project Num	State	County	Trans. Owner	Point of Interconnection	ERIS Output	NRIS Output	Fuel Type	Service Type
J955	IL	Sangamon	ATXI	Austin 345 kV	1040 sum/ 1165 win	1040 sum/ 1165 win	CC	NRIS
J956	MO	Ralls	UEC	Spencer Creek 345 kV	200	200	Solar	NRIS
J968	IN	Jasper, White	NIPS	Reynolds 345 kV	200	200	Wind	NRIS
J974	IL	Fulton, Peoria	AIC	Mapleridge 345 kV	250	250	Wind	NRIS
J976	MO	Warren	UEC	Montgomery - Enon 345 kV	300	300	Solar	NRIS
J979	IL	Christian	ATXI	Pana 345 kV	170	170	Wind	NRIS
J987	MO	Montgomery	UEC	Montgomery 161 kV	100	100	Solar	NRIS
J991	IL	Clay	AIC	Xenia 345 kV	150	150	Solar	NRIS
J992	IN	Cass	DEI	Walton 230 kV	200	200	Solar	NRIS
J993	IN	Boone	IPL	Hortonville - Whitestown 345 kV	200	200	Solar	NRIS
J994	MO	Callaway	UEC	Guthrie 161 kV	100	100	Solar	NRIS
J1022	IL	McLean	AIC	Weedman 138 kV	150	150	Wind	NRIS
J1025	MO	Knox	ATXI	Zachary - Maywood 345 kV	300	300	Wind	NRIS
J1026	MO	Audrain, Ralls	UEC	Maywood - Spencer Creek 345 kV	400	350	Wind	NRIS
J1027	IN	Pike	HE	Ratts 161 kV	150	150	Solar	NRIS
J1028	IN	Pike	HE	Ratts - Victory 161 kV	150	150	Solar	NRIS
J1033	MO	Stoddard	UEC	Stoddard - Morely 161 kV	50	50	Battery	NRIS
J1034	MO	Stoddard	UEC	Stoddard - Morley 161 kV	225	225	Solar	NRIS
J1039	MO	Warren	UEC	Enon - Montogomery 345 kV	50	50	Battery	NRIS
J1055	IL	Mason	AIC	Mason 138 kV	144	144	Wind	NRIS
J1058	IN	Lake	NIPS	Schahfer - St. John 345 kV	200	200	Solar	NRIS
J1063	IN	Clinton	DEI	New London - Frankfort 230 kV	195	195	Solar	NRIS
J1067	IN	Jasper, Pulaski	NIPS	Reynolds - Burr Oak 345 kV	240	240	Solar	NRIS
J1069	IN	Jasper, Pulaski	NIPS	Reynolds 345 kV	200	200	Wind	NRIS

MISO Project Num	State	County	Trans. Owner	Point of Interconnection	ERIS Output	NRIS Output	Fuel Type	Service Type
J1074	IN	Gibson	SIGE	Francisco 138 kV	200	200	Solar	NRIS
J1087	MO	Scott	UEC	Miner - Kelso 161 kV	200	200	Solar	NRIS
J1094	IL	Washington	AIC	Prest 138 kV	150	150	Solar	NRIS
J1096	IL	Saline	AIC	Norris City North - Muddy 138 kV	150	150	Solar	NRIS
J1102	IL	Logan	AIC	Fogarty 138 kV	70	70	Solar	NRIS
J1107	MO	Cape Girardeau	UEC	Kelso - Lutesville 345 kV	200	200	Solar	NRIS
J1111	IL	Jackson	SIPC	Campbell Hill - Jackson 161 kV	150	150	Solar	NRIS
J1112	IN	Kosciusko	NIPS	Leesburg 138 kV	150	150	Solar	NRIS
J1115	IL	Macon	AIC	Latham - Oreana 345 kV	200	200	Wind	NRIS
J1139	IL	Champaign	AIC	Sidney 138 kV	150	150	Solar	NRIS
J1145	MO	Callaway	UEC	Overton - (McCrede) - Montgomery 345 kV	250	250	Solar	NRIS
J1152	IN	Hancock, Shelby	IPL	Gwynneville - Sunnyside 345 kV	200	200	Solar	NRIS
J1180	IL	Clark	AIC	Casey West - Sullivan 345 kV	75	75	Solar	NRIS
J1182	MO	Adair	AIC	Zachary 345 kV	250	250	Solar	NRIS
J1189	IN	Brown, Martin	DEI	Crane Solar 69 kV	4.95	4.95	Battery	NRIS

Table A-4: DPP 2018 April Michigan Area Projects

MISO Project Num	State	County	Trans. Owner	Point of Interconnection	ERIS Output	NRIS Output	Fuel Type	Service Type
J984	MI	Gratiot	METC	Nelson Rd. 345 kV	200	200	Wind	NRIS
J989	MI	Oakland	METC	Halsey 138 kV	80	80	Solar	NRIS
J996	MI	Lenawee	METC	Beecher - Moraco 138 kV	80	80	Solar	NRIS
J1005	MI	Midland, Saginaw	METC	Murphy 345 kV	200	200	Solar	NRIS
J1043	MI	Montcalm	METC	Vergennes - Nelson Rd 345 kV	374.4	374.4	Wind	NRIS
J1062	MI	Washtenaw	ITCT	Majestic - Lemoyne 345 kV	150	150	Solar	NRIS
J1071	MI	Oceana	METC	Donaldson 138 kV	100	100	Solar	NRIS
J1088	MI	Shiawassee	METC	Cornell - Layton 138 kV	150	150	Solar	NRIS
J1089	MI	Shiawassee	METC	Cornell - Bell Rd 138 kV	170	170	Solar	NRIS
J1090	MI	Ingham	METC	Tompkins - Churchill Jct 138 kV	90	90	Solar	NRIS
J1103	MI	Tuscola	ITCT	Kirk 345 kV	20	20	Battery	NRIS
J1172	MI	Genesee	METC	Dort - Garfield 138 kV	50	50	Solar	NRIS
J1173	MI	Lenawee	CE	Raisin - METC Tap 138 kV	80	80	Solar	NRIS
J1178	MI	Eaton	METC	Oneida 138 kV	65	65	Solar	NRIS

Table A-5: DPP 2018 April ATC Area Projects

MISO Project Num	State	County	Trans. Owner	Point of Interconnection	ERIS Output	NRIS Output	Fuel Type	Service Type
J986	WI	Wood	ATC	Port Edwards - Sand Lake 138kV	149.76	149.76	Solar	NRIS
J1000	WI	Grant	ATC	Nelson Dewey 138 kV	50	50	Solar	NRIS
J1002	WI	Waushara	ATC	Wautoma 138 kV	99	99	Solar	NRIS
J1003	WI	Dodge	ATC	North Beaver Dam 69 kV	50	50	Solar	NRIS
J1042	WI	Walworth	ATC	North Lake Geneva 138 kV	180	180	Solar	NRIS
J1101	WI	Manitowoc	ATC	Kewaunee 138 kV	20	20	Battery	NRIS
J1153	WI	Sheboygan	ATC	Holland 138 kV	150	150	Solar	NRIS
J1154	WI	Jefferson	ATC	Jefferson 138 kV	75	75	Solar	NRIS
J1171	WI	Dodge	ATC	Butternut 138 kV	100	100	Solar	NRIS
J1183	MI	Delta	ATC	Heritage Garden	1.35	0	Solar	ERIS
J1188	WI	Rock	ATC	Sheepskin 69 kV	50	50	Solar	NRIS

A.2 Model Review Comments

Table A-6: Model Review Comments

Company	Python/ Idev File Name	2024 SH Study	2024 SH Benchmark	2024 SPK Study	2024 SPK Benchmark
ICs	J951 Comments.py	X	X	X	X
ICs	J1038 Comments.py	X	X	X	X
ICs	J1050 Comments.py	X	X	X	X
ICs	J1086 Comments.py	X	X	X	X
ICs	J1086 Comments_SH.py	X	X		
ICs	J1086 Comments_PK.py			X	X
ICs	J1092 Comments.py	X	X	X	X
ICs	J1098 Comments.py	X	X	X	X
ICs	J1106 Comments.py	X	X	X	X
ICs	J1108 Comments.py	X	X	X	X
ICs	J1109 Comments_SH.py	X	X		
ICs	J1109 Comments_PK.py			X	X
ICs	J1110 Comments.idv	X	X	X	X
ICs	J1114_Update_SH.idv	X	X		
ICs	J1114_Update_PK.idv			X	X
ICs	J1122 Comments.py	X	X	X	X
ICs	J1124 Comments.py	X	X	X	X
ICs	J1128 Comments.py	X	X	X	X
ICs	J1140 Comments.py	X	X	X	X
ICs	J1143 Comments.py	X	X	X	X
ICs	J1164 Comments.py	X	X	X	X
ICs	J1169 Comments.py	X	X	X	X
ICs	J1170 Comments.py	X	X	X	X
ICs	J1187 Comments.py	X	X	X	X
ATC	ATC_SH_Study.py	X			
ATC	ATC_SH_Bench.py		X		
ATC	ATC_PK_Study.py			X	
ATC	ATC_PK_Bench.py				X
CIPCO	CIPCO IR23_V33_SH.idv	X	X		
CIPCO	CIPCO IR23_V33_PK.idv			X	X
CIPCO	CIPCO IR24-IR34_V33_SH.IDV	X	X		

Company	Python/ Idev File Name	2024 SH Study	2024 SH Benchmark	2024 SPK Study	2024 SPK Benchmark
CIPCO	CIPCO IR24-IR34_V33_PK.IDV			X	X
MDU	MDU_Updates-DPP_2018_APR_West_Phase1_Models_190924.idv	X	X	X	X
MDU	J929_SH_Study.py	X			
MDU	J929_SH_Bench.py		X		
MDU	J929_PK_Study.py			X	
MDU	J929_PK_Bench.py				X
MEC	MEC_DPP_2018_APR_West_Ph1_SH_Updates.py	X	X		
MEC	MEC_DPP_2018_APR_West_Ph1_SUM_Updates.py			X	X
MEC	Turn off retirements.py	X	X	X	X
MEC	Correct V Control.py	X	X	X	X
MEC	Correct X 631144-41814-631139.py	X	X	X	X
MEC	Gen Correction_SH_Study.idv	X			
MEC	Gen Correction_SH_Bench.idv		X		
MEC	Gen Correction_PK_Study.idv			X	
MEC	Gen Correction_PK_Bench.idv				X
MP	J1143 POI Chng.py	X	X	X	X
MPC	MPC-fixrtngs-APR18_West_DPP-SH_study_190918.sav.idv	X	X	X	X
ICs	J1032 Chng.py	X	X	X	X
ICs	J1041 Chng.py	X	X	X	X
ICs	J1045 Chng.py	X	X	X	X
ICs	J1054 Chng.py	X	X	X	X
ICs	J1057 Chng.py	X	X	X	X
ICs	J1061 Chng.py	X	X	X	X
ICs	J1174 Chng.py	X	X	X	X
ICs	J1179 Chng.py	X	X	X	X
Changes applied to Phase 2 study					
MISO	RMV_DPP-2018-West_Ph1.py	X	X	X	X
MISO	RMV_DPP-2017Aug-West_Ph1.py	X	X	X	X
MISO	RMV_DPP-2018-ATC.py	X	X	X	X
MISO	RMV_DPP-2018-Central.py	X	X	X	X
MISO	RMV_DPP-2018-MI.py	X	X	X	X

Company	Python/ Idev File Name	2024 SH Study	2024 SH Benchmark	2024 SPK Study	2024 SPK Benchmark
MISO	SH-MW_Dec_DPP-2018.py	X	X		
MISO	PK-MW_Dec_DPP-2018.py			X	X
MISO	RMV_DPP-Prior.py	X	X	X	X
MISO	J963_Update.py	X	X	X	X
MISO	RMV_J528 NUs.py	X	X	X	X
MISO	RMV_J598 NUs.py	X	X	X	X
MISO	RMV DPP-2017Aug-Ph1_NUs.py	X	X	X	X
MISO	RMV DPP-2017Aug-Ph1_BaseCase NU.py	X	X	X	X
MISO	RMV DPP-2018Apr_BaseCase NU.py			X	X
MISO	RMV PJM Withdrawn Prjs.py	X	X	X	X
MISO	RMV SPP Withdrawn Prjs.py	X	X	X	X
MISO	Add Cap J1092.py	X	X	X	X
CIPCO	RMV CIPCO IR27.py	X	X	X	X
SPTI	Correct Areas.py	X	X	X	X
SPTI	Correct impedance.py	X	X	X	X
SPP	GEN-2016-096_POI.idv	X	X	X	X
SPP	GEN-2016-115_POI.idv	X	X	X	X
SPP	GEN-2014-021_Duplicate.idv	X	X	X	X
SPP	GEN-2015-005_Duplicate.idv	X	X	X	X
SPP	GEN-2015-007_Duplicate.idv	X	X	X	X
SPP	GEN-2016-151_Duplicate.idv	X	X	X	X
MISO	SH-MW_Dec_DPP-2018_West.py	X	X		
MISO	PK-MW_Dec_DPP-2018_West.py			X	X
MISO	RMV ATC J807_J819_J821.py	X	X	X	X
MISO	Remove NU J807 J819 J821.idv	X	X	X	X
MPC	MPC-fixrtngs-APR18_West_DPP_Ph2-ALL.idv	X	X	X	X
MDU	MDU-Updates_APR18_West_DPP_Ph2_AllModels.idv	X	X	X	X
MDU	MDU Move J580 POI.py	X	X	X	X
ITCM	Walters Removal.idv	X	X	X	X
MEC	MEC-DPP2018-APR-West-Ph2-Updates.py	X	X	X	X
ATC	J1000_Change_POI.idv	X	X	X	X
J1128	J1128 Update.py	X	X	X	X

Company	Python/ Idev File Name	2024 SH Study	2024 SH Benchmark	2024 SPK Study	2024 SPK Benchmark
MISO	RMV recent wd prjs.py	X	X	X	X
MISO	Update J1135.py	X	X	X	X

A.3 MISO North as the Study Sink

Table A-7: MISO North as the Study Sink

Area #	Area Name	Area #	Area Name
207	HE	608	MP
208	DEI	613	SMMPA
210	SIGE	615	GRE
216	IPL	620	OTP
217	NIPS	627	ALTW
218	METC	633	MPW
219	ITC	635	MEC
295	WEC	661	MDU
296	MIUP	663	BEPC-MISO
314	BREC	680	DPC
333	CWLD	694	ALTE
356	AMMO	696	WPS
357	AMIL	697	MGE
360	CWLP	698	UPPC
361	SIPC	701	MISO Prior
600	Xcel		

A.4 PJM Market as PJM Projects Sink

Table A-8: PJM Market as PJM Projects Sink

Area #	Area Name	Area #	Area Name
201	AP	230	PECO
202	ATSI	231	PSE&G
205	AEP	232	BGE
209	DAY	233	PEPCO
212	DEO&K	234	AE
215	DLCO	235	DP&L
222	CE	236	UGI
225	PJM	237	RECO
226	PENELEC	320	EKPC
227	METED	345	DVP
228	JCP&L	363	LGEE
229	PPL	703	PJM Prior

A.5 SPP Market as SPP Projects Sink

Table A-9: SPP Market as SPP Projects Sink

Area #	Area Name	Area #	Area Name
515	SWPA	541	KCPL
520	AEPW	542	KACY
523	GRDA	544	EMDE
524	OKGE	545	INDN
525	WFEC	546	SPRM
526	SPS	640	NPPD
527	OMPA	645	OPPD
531	MIDW	650	LES
534	SUNC	652	WAPA
536	WERE	659	BEPC-SPP
540	GMO	702	SPP Prior

A.6 Contingency Files used in Steady-State Analysis

Table A-10: List of Contingencies used in Steady-State Analysis

Contingency File Name	Description	Shoulder	Peak
Automatic single element contingencies	Single element outages at buses 60 kV and above in the study region	x	x
CC Bipole Events.con	Specified category P1, P7 contingencies in GRE Coal Creek	x	x
HVDC_Red_2024SH.con	Contingencies with HVDC reduction	x	
HVDC_Red_2024PK.con	Contingencies with HVDC reduction		x
MEC-DPP2018APRWESTPH1-Cat P1-2019.10.08.con	Specified category P1 contingencies in MEC	x	x
MEC-DPP2018APRWESTPH1-Cat P2-2019.10.08.con	Specified category P2 contingencies in MEC	x	x
MEC-DPP2018APRWESTPH1-Cat P5-2019.10.08.con	Specified category P5 contingencies in MEC	x	x
MEC-DPP2018APRWESTPH1-Cat P7-2019.10.08.con	Specified category P7 contingencies in MEC	x	x
MISO19_2024_SUM_TA_P1_ATC.con	Specified category P1 contingencies in ATC	x	x
MISO19_2024_SUM_TA_P1_IOWA.con	Specified category P1 contingencies in Iowa	x	x
MISO19_2024_SUM_TA_P1_MINN-DAKS.con	Specified category P1 contingencies in Minnesota, Dakotas	x	x
MISO19_2024_SUM_TA_P1_P2_P4_P5_NoLoadLoss.con	Specified category P1, P2, P4, P5 contingencies in MISO North	x	x
MISO19_2024_SUM_TA_P2_P4_P5_P7_LoadLoss.con	Specified category P2, P4, P5, P7 contingencies in MISO North	x	x
MISO19_2024_SUM_TA_P1_AMEREN.con	Specified category P1 contingencies in Ameren	x	x
2020_RTEP_Single_2017Aug-Updated-3-4-19.con	Specified single contingencies in PJM	x	x
2020_RTEP_Bus_AC2-updated-3-4-19.con	Specified bus contingencies in PJM	x	x
2020_RTEP_Line_FB_2017Aug-updated-3-4-19.con	Specified breaker failure contingencies in PJM	x	x
2020_RTEP_Tower_AC2-updated-3-4-19.con	Specified common structure contingencies in PJM	x	x
160303-KACY_P1.con	Specified category P1 contingencies in KACY	x	x
160303-KACY_P2.con	Specified category P2 contingencies in KACY	x	x
AECI-AMMO.CON	Specified contingencies between AECI and AMMO	x	x
KCPL_P1.con	Specified category P1 contingencies in KCPL	x	x
KCPL_P2.con	Specified category P2 contingencies in KCPL	x	x
KCPL_P4.con	Specified category P4 contingencies in KCPL	x	x

Contingency File Name	Description	Shoulder	Peak
KCPL_P5.con	Specified category P5 contingencies in KCPL	x	x
KCPL_P7.con	Specified category P7 contingencies in KCPL	x	x

Appendix

B

Model Data

B.1 Power Flow Model Data

CEII Redacted

B.2 Dynamic Model Data

CEII Redacted

B.3 2024 Slider Diagrams

CEII Redacted

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Appendix

C

Reactive Power Requirement Analysis Results (FERC Order 827)

Table C-1: Reactive Power Requirement Analysis Results

			Lagging Power Factor Results				Leading Power Factor Results					
Project #	Type	HV Side Bus #	MW from plant to HV side (P)	MVAR from plant to HV side (Q)	Lagging Power Factor at HV Side	Meet Lagging Power Factor Req.?	MW from plant to HV side (P)	MVAR from plant to HV side (Q)	Leading Power Factor at HV Side	Meet Leading Power Factor Req.?	Inverter Inherent Power Factor	Shunt Compensation
J952	Wind	89523	53.30	19.80	0.9374	Yes	53.10	-36.40	-0.825	Yes	+0.913 / -0.93	1×7.2 MVAR cap bank on 34.5 kV system
J959	Wind	89593	146.90	42.50	0.9606	No	146.40	-78.20	-0.882	Yes	± 0.95	2×9 MVAR cap bank on 34.5 kV system
J967	Wind	89673	146.90	51.90	0.9429	Yes	146.60	-77.40	-0.884	Yes	± 0.95	2×14 MVAR cap bank on 34.5 kV system
J975	Wind	89753	147.50	49.20	0.9486	Yes	147.00	-108.30	-0.805	Yes	± 0.90	1×6 MVAR cap bank on 34.5 kV system
J981	Wind	89813	190.10	55.30	0.9602	No	188.30	-109.60	-0.864	Yes	± 0.95	1×13.5 MVAR cap bank on each of the two 34.5 kV system
J982	Wind	89823	283.40	87.69	0.9553	No	281.87	-161.69	-0.867	Yes	± 0.95	1×25.5 MVAR cap bank on each of the two 34.5 kV system
J1001	Solar	40013	39.60	15.90	0.9280	Yes	39.60	-16.90	-0.920	Yes	± 0.95	1×6 MVAR cap bank on 34.5 kV system
J1024	Wind	40243	193.60	62.40	0.9518	No	192.40	-111.40	-0.865	Yes	± 0.95	1×30 MVAR cap bank on 34.5 kV system
J1040	Wind	40403	244.60	85.40	0.9441	Yes	244.20	-178.60	-0.807	Yes	± 0.90	1×17 MVAR cap bank on 34.5 kV system
J1045	Battery	88742	19.90	13.60	0.8256	Yes	19.80	-17.20	-0.755	Yes	± 0.794	None
J1050	Wind	40503	219.99	127.59	0.8650	Yes	219.40	-158.30	-0.811	Yes	± 0.90	2×15 MVAR cap bank on each of the two 34.5 kV system
J1072	Solar	40723	148.10	46.10	0.9548	No	148.00	-78.80	-0.883	Yes	± 0.95	2×12 MVAR cap bank on 34.5 kV system
J1084	Solar	40842	148.10	46.60	0.9539	No	148.00	-78.10	-0.884	Yes	± 0.95	2×12 MVAR cap bank on 34.5 kV system
J1092	Solar	40923	99.03	38.80	0.9311	Yes	98.90	-74.30	-0.800	Yes	± 0.90	1 x 12 MVAR cap bank on 34.5 kV system
J1098	Solar	601068	39.40	16.80	0.9199	Yes	39.30	-23.00	-0.863	Yes	± 0.90	None
J1105	Solar	40923	197.50	59.70	0.9572	No	197.20	-105.50	-0.882	Yes	± 0.95	2×14 MVAR cap bank on 34.5 kV system
J1106	Wind	41063	403.10	120.00	0.9584	No	400.90	-273.60	-0.826	Yes	+0.90 / -0.92	None
J1110	Solar	41103	98.53	32.35	0.9501	No	98.30	-68.50	-0.820	Yes	± 0.90	None
J1122	Wind	41223	195.00	90.80	0.9065	Yes	194.50	-104.00	-0.882	Yes	± 0.95	10×6 MVAR cap bank on 34.5 kV system
J1124	Solar	41243	98.50	32.00	0.9511	No	98.20	-71.40	-0.809	Yes	± 0.90	None
J1128	Solar	41283	147.60	36.70	0.9705	No	147.30	-86.60	-0.862	Yes	± 0.95	2×10 MVAR cap bank on 34.5 kV system
J1131	Solar	41313	98.00	37.40	0.9343	Yes	97.50	-88.40	-0.741	Yes	± 0.86	None
J1132	Solar	41323	49.00	19.80	0.9272	Yes	48.80	-41.60	-0.761	Yes	± 0.86	None
J1135	Solar	41353	49.20	21.00	0.9197	Yes	49.10	-40.10	-0.775	Yes	± 0.86	None
J1140	Solar	41403	77.60	33.80	0.9168	Yes	77.30	-46.20	-0.858	Yes	± 0.95	4×6.5 MVAR cap bank on 34.5 kV system
J1164	Solar	41643	79.30	13.50	0.9858	No	79.20	-40.30	-0.891	Yes	± 0.95	None
J1169	Solar	41693	49.40	25.70	0.8871	Yes	49.40	-24.20	-0.898	Yes	± 0.95	4×4 MVAR cap bank on 34.5 kV system
J1174	Solar	41743	161.60	59.80	0.9378	Yes	161.10	-109.30	-0.828	Yes	± 0.90	1×4 MVAR cap bank on 34.5 kV system
J1175	Wind	41753	161.10	62.00	0.9333	Yes	160.60	-110.45	-0.824	Yes	± 0.90	1×9 MVAR cap bank on 34.5 kV system
J1181	Wind	41813	196.40	69.60	0.9426	Yes	195.60	-144.40	-0.805	Yes	± 0.90	2×6 MVAR cap bank on 34.5 kV system
J1187	Wind	41873	148.71	17.10	0.9935	No	148.00	-91.20	-0.851	Yes	± 0.95	None

Appendix

D

2024 Summer Peak Contingency Analysis Results

D.1 Constraints in 2024 Summer Peak (SPK) Condition

Table D-1: 2024 SPK System Intact Thermal Constraints

Table D-2: 2024 SPK System Intact Voltage Constraints

Table D-3: 2024 SPK Category P1 Thermal Constraints

Table D-4: 2024 SPK Category P1 Voltage Constraints

Table D-5: 2024 SPK Category P2-P7 Thermal Constraints

Table D-6: 2024 SPK Category P2-P7 Voltage Constraints

Table D-7: 2024 SPK Non-Converged Contingencies

Table D-8: 2024 SPK Non-Converged Contingencies DCCC Results

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Appendix

E

2024 Summer Shoulder Contingency Analysis Results

E.1 Stage-1 Contingency Analysis Results

Table E-1: Non-Converged Contingencies in 2024 SH Scenario

Table E-2: Voltage Collapse (<0.87 p.u.) in 2024 SH Scenario

Table E-3: Voltage Violations (≥0.87 p.u.) in 2024 SH Scenario

Table E-4: Thermal Violations in 2024 SH Scenario

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E.2 Base Case Network Upgrades Justification Results

Table E-5: Potential Voltage Collapse Justification Results

Table E-6: Voltage Violations Justification Results

Table E-7: Thermal Violations Justification Results

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E.3 Stage-2 Contingency Analysis with Base Case NUs

Table E-8: Stage-2 SH System Intact Thermal Constraints

Table E-9: Stage-2 SH System Intact Voltage Constraints

Table E-10: Stage-2 SH Category P1 Thermal Constraints

Table E-11: Stage-2 SH Category P1 Voltage Constraints

Table E-12: Stage-2 SH Category P2-P7 Thermal Constraints

Table E-13: Stage-2 SH Category P2-P7 Voltage Constraints

Table E-14: Stage-2 SH Non-Converged Contingencies

Table E-15: Stage-2 SH Non-Converged Contingencies DCCC Results

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Appendix

F

Local Planning Criteria Analysis Results

F.1 GRE Local Planning Criteria Analysis Results

F.1.1 J1106 GRE Local Planning Criteria Analysis

Below is the J1106 GRE local planning criteria analysis report.

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F.1.2 J1140 GRE Local Planning Criteria Analysis

Below is the J1140 GRE local planning criteria analysis report.

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F.1.3 CCS (J1187) GRE Local Planning Criteria Analysis

Below is the CCS GRE local planning criteria analysis report.

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F.2 OTP LPC Analysis

Below is the OTP local planning criteria analysis report.

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F.3 MDU LPC Analysis

Below is the MDU local planning criteria analysis report.

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Appendix

G

Affected System Contingency Analysis Results

G.1 CIPCO Affected System Analysis Results

Table G-1: 2024 SPK CIPCO Affected System Analysis Results

Table G-2: 2024 SH CIPCO Affected System Analysis Results

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G.2 MPC Affected System Analysis Results

Below is the Affected System Analysis report provided by MPC.

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G.3 PJM Affected System Study Results

Below is the PJM affected system study report provided by PJM.

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G.4 AECI Affected System Study Results

Below is the AECI affected system study report provided by AECI.

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G.5 SPP Affected System Study Results

Below is the SPP affected system study report provided by SPP.

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Appendix

H

Transient Stability Results

H.1 2024 Summer Peak Stability Results

Stability simulation was performed in the 2024 summer peak (PK) Phase 2 stability model without any steady state ERIS Network Upgrades identified in DPP 2018 April Phase 2.

H.1.1 2024 SPK Stability Summary

Summer peak stability study results are summarized in **Table H-1**.

Table H-1: 2024 Summer Peak Phase 2 Stability Analysis Results Summary

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H.1.2 2024 SPK Stability Plots

Plots of stability simulations for 2024 summer peak Phase 2 study case are in separate files which are listed below:

AppendixH1_2024SPK_DPP 2018Apr-West_Ph2_Study_Plots.zip

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H.2 2024 Summer Shoulder Stability Results

Stability simulation was performed in the 2024 summer shoulder stability case with DPP 2018 April Phase 2 steady state ERIS Network Upgrades (Table 4-3, Table 4-4, Table 4-5) and switched capacitors (Table 7-1) which are required ERIS NUs in DPP 2017 August Phase 2.

H.2.1 2024 SH Stability Summary

Stability study results are summarized in Table H-2.

Table H-2: 2024 Summer Shoulder Phase 2 Stability Analysis Results Summary

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H.2.2 2024 SH Stability Plots

Plots of stability simulations for 2024 summer shoulder Phase 2 study case are in separate files which are listed below:

AppendixH2_2024SH_DPP 2017Feb-West_Ph2_Study_Plots.zip

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Appendix

I

MWEX Voltage Study Details

Below is the MWEX voltage stability study report provided by ATC.

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Appendix

J

Short Circuit Analysis

J.18 J1122 Short Circuit Study

J.19 J1124 Short Circuit Study

J.20 J1128 Short Circuit Study

J.21 J1131 Short Circuit Study

J.22 J1132 Short Circuit Study

J.23 J1135 Short Circuit Study

J.24 J1140 Short Circuit Study

J.25 J1164 Short Circuit Study

J.26 J1169 Short Circuit Study

J.27 J1174 & J1175 Short Circuit Study

J.28 J1181 Short Circuit Study

J.29 J1187 Short Circuit Study

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Appendix

K

2024 Cost Allocation Results

K.1 Distribution Factor (DF), Voltage Impact, and MW Contribution Results for Cost Allocation in 2024

Table K-1: Voltage Impact on Hazel Creek-Scott County 345 kV Base Case NU Cost Allocation

Table K-2: Distribution Factor and MW Contribution on Constraints for Other Thermal NU Cost Allocation

Table K-3: Voltage Impact on MISO Voltage NUs Cost Allocation

Table K-4: Voltage Impact on MISO Stability Voltage NUs Cost Allocation

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K.2 Cost Allocation Details

Table K-5: Network Upgrades Cost Allocation in 2024

Table K-5: Network Upgrades Cost Allocation in 2024

Monitored Element	English Name	Owner	Cost	J952	J953	J954	J959	J963	J967	J975	J981	J982	J1001	J1024	J1040	J1045	J1050	J1072	J1084	J1092	J1098	J1105	J1106	J1110	J1122	J1124	J1128	J1131	J1132	J1135	J1140	J1164	J1169	J1174	J1175	J1181	J1187	Upgrade for
Hazel Creek-Scott Co. 345 kV	Hazel Creek-Scott Co. 345 kV	XEL	$210,829,263	$0	$0	$0	$403,887	$0	$1,211,662	$0	$0	$16,155,499	$0	$0	$0	$0	$0	$1,615,550	$0	$10,904,962	$0	$4,442,762	$144,591,717	$403,887	$0	$2,423,325	$0	$0	$0	$0	$27,464,348	$0	$0	$0	$0	$1,211,662	$0	Base Case NU Hazel Creek-Scott Co. 345
40244 J1024 POI 161 635034 CLARINDA 5 161 1	J1024 POI-Clarinda 161 kV	MEC	$700,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$700,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
41814 J1181 POI 345 631139 HAZLTON3 345 1	J1181 POI-Hazleton 345 kV	MEC ITCM	$600,000	$0	$0	$0	$0	$0	$155,837	$0	$0	$0	$0	$0	$0	$0	$0	$77,918	$0	$0	$0	$0	$0	$0	$0	$33,353	$0	$0	$0	$0	$0	$0	$0	$0	$0	$332,892	$0	MISO SH
86111 J611 POI 161 541251 MARYVLE5 161 1	J611 POI-Maryville 161 kV	MEC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
87208 J720 POI 345 631138 LAKEFLD3 345 1	J720 POI-Lakefield 345 kV	ITCM	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
560074 G16-017-TAP 345 652816 FTTHOM1-LNX3 345 1	G16-017 Tap-Ft. Thompson 345 kV	WAPA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
601004 WILMART3 345 601033 FIELD_N3 345 1	Wilmarth-Field North 345 kV	XEL	$96,300,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$96,300,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
601004 WILMART3 345 601072 SHEAS LK3 345 1	Wilmarth-Sheas Lake 345 kV	XEL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
601006 SPLT RK3 345 652537 WHITE 3 345 1	Split Rock-White 345 kV	XEL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
601015 BLUE LK3 345 601055 SCOTTCO3 345 1	Blue Lake-Scott Co 345 kV	XEL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
601032 FIELD_S3 345 601033 FIELD_N3 345 1	Field South-Field North 345 kV	XEL	$500,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$500,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
601032 FIELD_S3 345 601074 CRANDAL 3 345 1	Field South-Crandal 345 kV	XEL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
601048 LYON CO 3 345 601054 HAZEL CR3 345 1	Lyon Co-Hazel Creek 345 kV	XEL	$200,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$200,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
601050 HELENA 3 345 601072 SHEAS LK3 345 1	Helena-Sheas Lk 345 kV	XEL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
602006 SHEYENNE4 230 620337 LAKE PARK T4 230 1	Sheyenne-Lake Park 230 kV	XEL MPC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
603018 SHEYNNE7 115 620203 MAPLTN 7 115 1	Sheyenne-Mapleton 115 kV	XEL OTP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH & PK
603042 MEI INT7 115 619402 GRE-WESTWD 7 115 1	M.E. International-Westwood 115 kV	XEL GRE	$5,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,000,000	$0	$0	$0	$0	$0	$0	MISO SH
613040 AUSTIN 5 161 613042 MURPHY CR 5 161 1	Austin-Murphy 161 kV	SMMPA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
613042 MURPHY CR 5 161 41284 J1128 POI 161 1	Murphy-J1128 POI 161 kV	SMMPA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
615341 GRE-HUBBARD4 230 608610 BADOURA4 230 1	Hubbard-Badoura 230 kV	MP	$1,350,000	$0	$0	$0	$0	$0	$0	$1,350,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
615560 GRE-WST CLD7 115 619402 GRE-WESTWD 7 115 1	West St. Cloud-Westwood 115 kV	GRE XEL	$900,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$900,000	$0	$0	$0	$0	$0	$0	MISO SH
615650 GRE-CHUBLAK7 115 615649 GRE-CHUBLAK3 345 615651 GRE-CHUBLAKT34.5 1	Chub Lake 345-115-34.5 kV xfmr	GRE	$11,400,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$11,400,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
619412 GRE-STSTPHT7 115 619407 GRE-FSCHRHL7 115 1	STSTPHNT-Fishill 115 kV	GRE	$5,100,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,100,000	$0	$0	$0	$0	$0	$0	MISO SH
620180 CSLTNET7 115 620203 MAPLTN 7 115 1	CSLTNET-Mapleton 115 kV	OTP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
620258 BUFFALO7 115 620358 BUFFALO3 345 620858 BUFFALO 9X 41.6 2	Buffalo 345-230-41.6 kV xfmr #2	OTP	$3,000,000	$0	$0	$0	$0	$0	$0	$3,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
620327 HANKSON4 230 620363 FORMAN 4 230 1	Hankinson-Forman 230 kV	OTP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
620329 WAHPETN4 230 658109 FERGSFL4 230 1	Wahpeton-Fergus Falls 230 kV	OTP MRES	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
620336 AUDUBON4 230 620337 LAKE PARK T4 230 1	Audubon-Lake Park 230 kV	OTP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
620417 BSSOUTH3 345 620322 BSSOUTH4 230 620320 BSS1 34.5 34.5 1	Big Stone South 345-230-34.5 kV #1	OTP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
620417 BSSOUTH3 345 620322 BSSOUTH4 230 620321 BSS2 34.5 34.5 2	Big Stone South 345-230-34.5 kV #2	OTP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
629990 ELLENDALE5 69.0 630130 CO LINE8 69.0 1	Ellendale-County Line 69 kV	ITCM	$4,200,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,200,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
630129 HAYWARD J2 869.0 630130 CO LINE8 69.0 1	Hayward-County Line 69 kV	ITCM	$9,700,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$9,700,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
630451 OSCELA_8 69.0 630452 OSCEREC8 69.0 1	Osceola-Osceola REC 69 kV	ITCM	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
631123 ADAMS L2 5 161 631127 HAYWARD L1 5 161 1	Adams-Hayward 161 kV	ITCM	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
631139 HAZLTON3 345 631142 ARNOLD 3 345 1	Hazleton-Arnold 345 kV	ITCM MEC	$1,280,000	$0	$0	$0	$325,858	$0	$284,077	$0	$0	$0	$0	$0	$0	$0	$0	$142,038	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$528,027	$0	MISO SH
631139 HAZLTON3 345 631191 HCKRYCK3 345 1	Hazleton-Hickory Crk 345 kV	ITCM	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
635056 ADAMS 5 161 652560 CRESTON5 161 1	Adams-Creston 161 kV	MEC	$800,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$800,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
636001 WEBSTER5 161 636050 WRIGHT 5 161 1	Webster-Wright 161 kV	MEC	$8,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,666,667	$5,333,333	$0	$0	MISO SH
636230 FRANKLN5 161 636235 WALL LK5 161 1	Franklin-Wall Lake 161 kV	MEC	$12,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,000,000	$8,000,000	$0	$0	MISO SH
640325 REDWILO3 345 531451 MINGO 7 345 1	Red Willow-Mingo 345 kV	NPPD	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
652296 WARD 4 230 652426 BISMARK4 230 1	Ward-Bismark 230 kV	BEPC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
652506 FTTHOMP3 345 652806 FTTHOM1-LNX3 345 Z	Ft. Thompson 345 kV bus 1-3 TIE	WAPA	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
657708 WILTON 4 230 657758 WINGER 4 230 1	Wilton-Winger 230 kV	MPC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
661027 ELLENDL7 115 660000 ABERDN JCT 7 115 1	Ellendale-Aberdeen 115 kV	MDU	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
661042 HESKETT4 230 83021 J302 POI 230 1	Heskett-J302 POI 230 kV	MDU	$81,500,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$81,500,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
661042 HESKETT4 230 661053 MANDAN 4 230 1	Heskett-Mandan 230 kV	MDU	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
661043 HESKETT7 115 661042 HESKETT4 230 661906 HESKETT9 13.8 1	Heskett 230-115-13.8 kV xfmr	MDU	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
661053 MANDAN 4 230 652296 WARD 4 230 1	Mandan-Ward 230 kV	MDU	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
661092 FOXTAIL 4 230 661096 TTANKANORTH4 230 1	Fox Tail-Tatanka North 230 kV	MDU	$1,500,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,500,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
661092 FOXTAIL 4 230 661098 ELLENDL345 4 230 1	Fox Tail-Ellendale 230 kV	MDU	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
661093 MERRCRT4 230 661094 WISHEK 4 230 1	Merricourt-Wishek 230 kV	MDU	$15,000,000	$161,529	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$14,104,306	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$734,165	MISO SH
661093 MERRCRT4 230 661096 TTANKANORTH4 230 1	Merricourt-Tatanka North 230 kV	MDU	$1,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
661093 MERRCRT4 230 661098 ELLENDL345 4 230 1	Merricourt-Ellendale 230 kV	MDU	$15,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$15,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
661094 WISHEK 4 230 83021 J302 POI 230 1	Wishek-J302 POI 230 kV	MDU	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO SH
681532 WABACO 5 161 681537 ROCHSTR5 161 1	Wabaco-Rochester 161 kV	DPC	$11,000,000	$0	$0	$0	$0	$0	$3,845,005	$0	$0	$0	$0	$0	$0	$0	$0	$1,157,197	$0	$0	$0	$0	$0	$602,883	$0	$959,873	$952,189	$0	$0	$0	$0	$0	$0	$0	$0	$3,482,853	$0	MISO SH
681532 WABACO 5 161 681543 ALMA 5 161 1	Wabaco-Alma 161 kV	DPC	$6,300,000	$0	$0	$0	$0	$0	$3,294,529	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,005,471	$0	MISO SH
1×40 Mvar switched capacitor at Oakes 230 kV (620362)	1×40 Mvar switched capacitor at Oakes 230 kV (620362)	OTP	$2,000,000	$34,653	$0	$0	$0	$0	$0	$0	$3,300	$47,855	$9,901	$33,003	$1,628,713	$9,901	$31,353	$0	$0	$0	$0	$0	$8,251	$0	$36,304	$0	$0	$0	$3,300	$0	$0	$14,851	$11,551	$4,950	$13,201	$0	$108,911	MISO Voltage
Stability voltage NU	CCS GRE LPC benchmark voltage NU	Multiple	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MISO Stability
630380 MURRAY 8 69.0 630853 I35TAP 69.0 1	Murray-I35 Tap 69 kV	CIPCO	$1,988,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,988,000	$0	$0	$0	$0	$0	$0	$0	$0	CIPCO
630451 OSCELA_8 69.0 630452 OSCEREC8 69.0 1	Osceola-Osceola REC 69 kV	ITCM	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	CIPCO
631100 LIBERTY5 161 631159 HCKRYCK5 161 1	Liberty-Hickory Crk 161 kV	CIPCO	$100,000	$0	$0	$0	$37,301	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$9,959	$19,918	$32,823	$0	CIPCO
615341 GRE-HUBBARD4 230 620326 ERIEJCT 230 1	Hubbard-Erie Jct 230 kV	GRE OTP MP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	CCS GRE LPC
615560 GRE-WST CLD7 115 619410 GRE-LSAUKTP7 115 1	West St. Cloud-Lesauk Tap 115 kV	GRE XEL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	J1140, CCS GRE LPC
615649 GRE-CHUBLAK3 345 601050 HELENA 3 345 1	Helena-Chub Lake 345 kV	GRE CAPX	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	J1106 GRE LPC
615901 GRE-STANTON4 230 659106 LELAND_O-BE4 230 1	Stanton-Leland Olds 230 kV	GRE	$2,500,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,500,000	CCS GRE LPC
619410 GRE-LSAUKTP7 115 619407 GRE-FSCHRHL7 115 1	Lesauk Tap-Fishill 115 kV	GRE XEL	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	J1106, J1140, CCS GRE LPC
620326 ERIEJCT 230 620336 AUDUBON4 230 1	Erie Jct-Audubon 230 kV	OTP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	OTP LPC SH
661029 ESTBMRK7 115 652427 BISMARK7 115 1	East Bismark-Bismark 115 kV	MDU	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MDU LPC
661053 MANDAN 4 230 83021 J302 POI 230 1	Mandan-J302 POI 230 kV #1	MDU	$48,400,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$48,400,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MDU LPC
661053 MANDAN 4 230 652296 WARD 4 230 1	Mandan-Ward 230 kV	MDU	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	MDU LPC
Nelson;B- Electric JCT;R 345 kV	Nelson;B- Electric JCT;R 345 kV	PJM	$36,200,000	$0	$0	$0	$0	$0	$0	$0	$7,650,000	$6,410,000	$0	$0	$0	$0	$0	$0	$9,770,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$5,920,000	$0	PJM
Reconductor MCKSBRG-Winterset	Reconductor MCKSBRG-Winterset	ITCM MEC	$10,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$6,367,594	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,632,406	$0	$0	$0	$0	$0	$0	$0	$0	NRIS
Council Bluffs-S3456 345 kV Terminal Equipment Upgrade	Council Bluffs-S3456 345 kV Terminal Equipment Upgrade	MEC OPPD	$200,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$31,263	$0	$0	$18,345	$0	$0	$0	$0	$0	$0	$0	$144,859	$0	$0	$0	$5,533	$0	$0	$0	$0	$0	$0	$0	$0	NRIS
Winterset-Norwalk Structure Replacements	Winterset-Norwalk Structure Replacements	ITCM MEC	$300,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$189,586	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$110,414	$0	$0	$0	$0	$0	$0	$0	$0	NRIS
Adams-Creston Structure Replacements	Adams-Creston Structure Replacements	MEC WAPA	$800,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$800,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	NRIS
Second Webster 345/115 kV Transformer	Second Webster 345/115 kV Transformer	MEC	$10,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	NRIS
2nd Coyote 345/115 kV Transformer	2nd Coyote 345/115 kV Transformer	MDU	$7,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,000,000	NRIS
New Square Butte-Mandan 230 kV Line	New Square Butte-Mandan 230 kV Line	MDU MPC	$31,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$31,000,000	NRIS
East Bismark Terminal Upgrades	East Bismark Terminal Upgrades	MDU	$100,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$100,000	NRIS
Drayton 230-115 kV xfmr 1	Drayton 230-115 kV xfmr 1	MPC	$2,100,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,100,000	MPC
Prairie-Walle 230 kV	Prairie-Walle 230 kV	MPC	$6,000,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,323,563	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,676,437	MPC
Essex-Stoddard 161 kV line	Essex-Stoddard 161 kV line	AECI	$861,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	AECI
Green Forest-Township 69 kV line	Green Forest-Township 69 kV line	AECI	$2,895,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	AECI
SPP ERIS Network Upgrades	SPP ERIS Network Upgrades	SPP	$21,700,000	$8,700,000	$0	$0	$0	$0	$0	$215,892	$0	$0	$0	$12,000,000	$465,966	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$318,142	SPP
SPP NRIS Network Upgrades	SPP NRIS Network Upgrades	SPP	$35,830,140	$0	$0	$0	$50,359	$0	$74,983	$0	$0	$268,197	$34,839	$0	$176,076	$18,588	$2,000,000	$74,983	$0	$57,759	$252,503	$126,630	$323,611	$4,419,388	$0	$54,356	$7,882,204	$0	$0	$0	$52,363	$759,941	$1,968,089	$8,526,060	$8,526,060	$80,191	$102,960	SPP
Total Cost Per Project for Actual NRIS Elections for each Project	**Total Cost Per Project for Actual NRIS Elections for each Project**		**$701,927,403**	**$8,896,182**	**$0**	**$0**	**$817,405**	**$0**	**$5,021,088**	**$4,565,892**	**$7,653,300**	**$22,881,551**	**$44,740**	**$20,921,447**	**$166,098,624**	**$28,489**	**$2,049,698**	**$1,910,489**	**$9,770,000**	**$10,962,721**	**$107,052,503**	**$15,969,392**	**$145,123,579**	**$4,823,275**	**$181,162**	**$2,511,034**	**$21,782,204**	**$0**	**$5,739,653**	**$0**	**$38,516,711**	**$774,792**	**$1,979,640**	**$15,207,636**	**$21,892,512**	**$11,111,066**	**$47,640,615**	

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